STANDARD LITHIUM LTD.
PRELIMINARY ECONOMIC ASSESSMENT OF SW ARKANSAS LITHIUM PROJECT
NI 43 – 101 TECHNICAL REPORT

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

Information contained in this report and the documents referred to herein which are not statements of historical facts, may be "forward-looking information" for the purposes of Canadian Securities laws. Such forward looking information involves risks, uncertainties and other factors that could cause actual results, performance, prospects and opportunities to differ materially from those expressed or implied by such forward looking information. The words "expect", "target", "estimate", "may", "anticipate", "should", "will", and similar expressions identify forward-looking information.

These forward-looking statements relate to, among other things, resource estimates, grades and recoveries, development plans, mining methods and metrics including recovery process and, mining and production expectations including expected cash flows, capital cost estimates and expected life of mine, operating costs, the expected payback period, receipt of government approvals and licenses, time frame for construction, financial forecasts including net present value and internal rate of return estimates, tax and royalty rates, and other expected costs.

Forward-looking information is necessarily based upon a number of estimates and assumptions that, while considered reasonable, are inherently subject to significant political, business, economic and competitive uncertainties and contingencies. There may be factors that cause results, assumptions, performance, achievements, prospects or opportunities in future periods not to be as anticipated, estimated or intended.

There can be no assurances that forward-looking information and statements will prove to be accurate, as many factors and future events, both known and unknown could cause actual results, performance or achievements to vary or differ materially, from the results, performance or achievements that are or may be expressed or implied by such forward-looking statements contained herein or incorporated by reference. Accordingly, all such factors should be considered carefully when making decisions with respect to the Project, and prospective investors should not place undue reliance on forward-looking information. Forward-looking information in this technical report is as of the original issue date, November 25, 2021. Standard Lithium Ltd. assumes no obligation to update or revise forward-looking information to reflect changes in assumptions, changes in circumstances or any other events affecting such forward-looking information, except as required by applicable law.

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1 SUMMARY

1.1 Issuer and Purpose

This Technical Report has been commissioned by, and completed for, Standard Lithium Ltd. (Standard Lithium), a public company with its corporate headquarters in Vancouver, British Columbia, Canada. Standard Lithium is focused on unlocking the lithium potential of existing large-scale United States-based brine operations that include the LANXESS and South West Arkansas Lithium projects in south-central and west-central Arkansas, respectively.

At the South West Arkansas Lithium Project (SWA Project or Property), which is the focus of this Technical Report, Standard Lithium has outlined how it could unitise the underlying Smackover Formation brine aquifer in conjunction with the preparation of a Preliminary Economic Assessment (PEA). This Technical Report updates the 2019 maiden Inferred Resource estimate and applies a gross acreage with 100% brine ownership that is consistent with unitisation within the Arkansas Brine Statute. This PEA also outlines a proposed method of extraction of the brine from the resource, a proposed flowsheet to extract and purify the lithium to potentially produce a marketable product, as well as other necessary SWA Project information.

1.2 Property Location and Ownership

The centre of the SWA Project is located approximately 24 km (15 miles) west of the City of Magnolia in Lafayette County, south western Arkansas, United States. The SWA Property encompasses Townships 16-17 South and Ranges 22-24 West of the 5th Meridian and lies wholly within Lafayette and Columbia counties.

The SWA Property is comprised of 489 land tracts containing 802 individual leases and eight salt water (brine) deeds that covers 11,033 net mineral hectares (27,262 net mineral acres). The proposed unitised SWA Property encompasses 14,638 gross mineral hectares (36,172 gross mineral acres) and forms the updated 2021 resource and project area.

The leases and deeds are held by TETRA Technologies Inc. (TETRA). Standard Lithium acquired the SWA Project brine production rights to lithium directly from TETRA through an option agreement providing that Standard Lithium makes annual payments. TETRA began acquiring brine deeds and/or brine leases in 1992 and added additional brine leases in 1994, 2006 and 2017. The SWA Project brine leases and deeds have yet to be developed for production of brine minerals.

1.3 Geology and Inferred Resource Estimation

The lithium brine Inferred Resource, as reported, is contained within the Upper and Middle Members of the Smackover Formation, a late Jurassic oolitic limestone aquifer that underlies the entire Project area. The Upper and Middle Smackover formations aquifer is situated at a depth of approximately 2,700 m (or about 8,800 feet) beneath ground level. This brine resource is in an area where there is localised oil and gas production, and where brine is produced as a by-product of hydrocarbon extraction. The data used to estimate and model the resource were gathered from existing and suspended oil and gas production wells on or adjacent to the SWA Project and surface seismic information.

The resource present in the Smackover Formation below the SWA Project was updated based on the proposed unitized area encompassing 36,172 gross mineral acres (14,638 gross mineral hectares. Using a cut-off criteria of 50 mg/L lithium, the SWA Project resource estimate is classified as 'Inferred' according to the Canadian Institute of Mining (CIM) definition standards (see note 4 after Table 1-1). The total (global) in-situ 'Inferred' lithium brine resource is estimated at 225,000 tonnes of elemental lithium, or 1,195,000 tonnes lithium carbonate equivalent ("LCE"); see Table 1-1 below for more detail.

Table 1-1. SWA Project Inferred Resource estimation

	Upper Smackover Formation		Middle Smackover Formation		Total (and main resource)[1,2]
Parameter	South Resource Area	North Resource Area	South Resource Area	North Resource Area	
Aquifer Volume (km^3)	2.852	4.226	0.704	1.080	8.862
Brine Volume (km^3)	0.281	0.416	0.071	0.110	0.878
Average Lithium concentration (mg/L)	399	160	399	160	255
Average Porosity	10.1 %	10.1 %	10.3 %	10.3 %	10.1 %
Total Li inferred resource (as metal) metric tonnes [4][5]	112,000	67,000	28,000	18,000	225,000
Total LCE inferred resource (metric tonnes)[4][5]	596,000	354,000	152,000	93,000	1,195,000

Notes:

[1] Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve. The estimate of mineral resources may be materially affected by geology, environment, permitting, legal, title, taxation, socio-political, marketing, or other relevant issues.

[2] Numbers may not add up due to rounding to the nearest 1,000 unit).

[3] The resource estimate was completed and reported using a cut-off of 50 mg/L lithium.

[4] The resource estimate was developed and classified in accordance with guidelines established by the Canadian Institute of Mining and Metallurgy (CIM). The associated Technical Report was completed in accordance with the

Canadian Securities Administration's National Instrument 43-101 and all associated documents and amendments. As per these guidelines, the resource was estimated in terms of metallic (or elemental) lithium.

[5] In order to describe the resource in terms of 'industry standard' lithium carbonate equivalent (LCE), a conversion factor of 5.323 was used to convert elemental lithium to LCE.

The average lithium concentrations used in the resource calculation are 399 mg/L and 160 mg/L, for the South and North resource areas, respectively. Resources have been estimated using a cut-off grade of 50 mg/L lithium.

With respect to reconciliation of resources, the updated 2021 SWA Project resource is 49% larger than the 2019 resource estimate. This difference is directly related to proposed future unitization of the resource area. More specifically, the total aquifer volume has increased from 7.66 km^3 in 2019 to 8.86 km^3 (1.84 mi^3 to 2.13 mi^3) in this Technical Report.

1.4 Recovery Method and Mineral Processing

Standard Lithium's objective is to produce battery-grade lithium hydroxide monohydrate (LHM) from the brine produced from the Smackover Formation. A network of 23 brine supply wells would produce from the Smackover Formation in the higher-grade South resource area averaging about 1,715 m^3/day per well for an aggregated total production of 39,452 m^3/day (1,644 m^3/hr or 7,238 US gallons per minute). Brine from the supply wells would be conveyed to a single combined lithium extraction and lithium hydroxide production facility by a network of underground fibreglass pipelines totalling approximately 18.3 km (11.4 miles) in length. The brine entering the processing facility would be pre-treated to remove hydrogen sulphide gas (H_2S), suspended solids and hydrocarbons, prior to processing by the Company's proprietary direct lithium extraction process (LiSTR). After lithium extraction, the lithium depleted brine is returned to the lower lithium-grade North resource area by a pipeline system 20.3 km (12.6 miles) in length to a network of 24 brine reinjection wells completed in the Smackover Formation. The project as proposed would produce, on average, 30,000 tonnes of battery-quality LHM per year, over a 20-year timeframe. The final product lithium recovery is about 90%.

The production process parameters are supported by bench scale metallurgical testing, mini-pilot plant testing and Demonstration Plant program results. It is the Company's plan to take large-scale brine samples from the SWA Property, and test using the LiSTR proprietary technology, at the Demonstration Plant located at LANXESS's South Plant. The Demonstration Plant is located about 40 km (25 miles) east of the SWA Project. It is the Company's intent to use the information obtained from the large-scale brine samples to gather specific data related to lithium extraction scalability and economics.

1.5 Capital and Operating Cost Estimates

1.5.1 Capital Expenditure Costs

At full build-out, with estimated average production over 20 years of 30,000 tonnes per annum of LHM, the direct capital costs are estimated to be US$532 million, with indirect costs of US$205 million. A contingency of 25% was applied to direct costs (US$133 million) to yield an estimated all-in capital cost of US$870 million. A summary of the capital costs is provided in Table 1-2.

Table 1-2. Capital cost summary

Description	Direct Costs Million US$[1]	Indirect Costs Million US$[2]
Extraction and Reinjection Wellfield[3]	204.9	2.3
Pipelines[3]	38.7	2.5
Receiving/Pre-Treatment	35.4	28.1
Lithium Extraction (LiSTR)	135.0	103.8
Lithium Hydroxide Conversion	90.9	39.9
Utilities/Infrastructure	26.9	28.5
Contingency	133.0[4]	-
Total	664.8	205.1
CAPEX TOTAL	US$869.9 million	

Notes:

[1] Direct costs were estimated using either vendor-supplied quotes, and/or engineer estimated pricing (based on recent experience) for all major equipment. Major equipment prices were scaled using appropriate AACE Class 5 Direct Cost Factors (provided by the relevant QP) to derive all direct equipment costs

[2] Indirect costs were estimated using AACE Class 5 Indirect Cost Factors multiplied by the direct costs. Indirect costs include all contractor costs (including engineering); indirect labor costs and Owner's Engineer costs

[3] Exceptions to above costing estimate methodology were the wellfield and pipelines, which were based on HGA's recent project experience in the local area

[4] AACE Class 5 estimate includes 25% contingency on direct capital costs

1.5.2 Operating Expenditure Costs

The operating cost estimate includes both direct costs and indirect costs, as well as allowances for mine closure (see Table 1-3). The majority of the operating cost comprises reagent usage required to extract the lithium from the brine, as well as conversion to LHM and electricity consumption. Out of this, the greatest amount is related to acid and base consumption (hydrochloric acid and ammonium hydroxide) and was estimated using information from the operating Demonstration Plant located in Union County, Arkansas. The all-in operating cost of $2,599 per tonne of LHM is one of the lowest reported in the industry owing to two key factors which are location-specific. The direct lithium extraction (DLE) processes are reagent intensive; in the case of the LiSTR process, the principal reagent is hydrochloric acid. A large portion (approximately 50%) of the acid required is produced on-site as a by-product of the electrochemical conversion of lithium chloride to lithium hydroxide. This results in significant cost-savings during the DLE step. The electrochemical conversion uses a large quantity of electricity, which would normally (in most jurisdictions around the world) result in a cost disbenefit; however, bulk electricity pricing in southern Arkansas is favorable (<6 cents/kWh), and hence results in overall lower-than-normal operating costs.

Table 1-3. Operating cost summary

Description	Operating Cost US$/tonne LHM[1]
Workforce[2]	190
Electrical Power[3]	378
Reagents and Consumables[4]	836
Natural Gas[5]	39
Maintenance/Waste Disposal/Misc[6]	563
Indirect Operational Costs[7]	110
Royalties and Land/Lease Costs[8]	482
OPEX Total	2,599

Notes:

[1] Operating costs are calculated based on average annual production of 30,000 tonnes of LHM

[2] Approximately 75 full time equivalent (FTE) positions

[3] Approximately 40% of electrical energy consumed by wellfield and pipelines; 60% by the processing facilities

[4] Majority of reagent costs are comprised of hydrochloric acid and ammonium hydroxide consumption. As discussed above, approximately 50% of the required hydrochloric acid is produced on-site as a by-product of the electrochemical conversion of lithium chloride solution to lithium hydroxide solution, resulting in a significant cost saving. Additional cost savings can be attributed to the on-site production of concentrated sodium chloride solution, resulting from pre-concentration of the lithium chloride ahead of conversion. This sodium chloride solution is used as a regenerant in some of the polishing ion exchange (IX) processes. Other reagents and consumables are air, lithium titanate make-up (owing to small losses in the process), membrane replacement, nitrogen and scale inhibitors for pumps/wellheads.

[5] Assumes that all natural gas is purchased from open market and none is co-produced at the wellheads

[6] Includes all maintenance and workover costs and is based on experience in similar-sized electrochemical facilities, brine processing facilities and Smackover Formation brine production wellfields

[7] Indirect costs (insurance, environmental monitoring, community benefits etc.) are factored from other capital and operational costs, except for mine closure, which is based on known well-abandonment costs

[8] Based on agreed royalties and expected future lease costs. Does not include future lease-fees-in-lieu-of-royalties which are still to be determined and subject to regulatory approval (lease-fees-in-lieu-of-royalties have been determined for bromine and certain other minerals in the State of Arkansas, but have not yet been determined for lithium extraction)

1.6 Economic Analysis

The SWA Project economics assumed a selling price of battery quality LHM based on an initial price of US$14,500/tonne in 2021, adjusted for inflation at 2% per annum. The results for internal rate of return (IRR) and net present value (NPV) from the assumed CAPEX, OPEX and price scenario at full production, are presented in Table 1-4.

Table 1-4. Economic evaluation summary

Description	Units	Values
Average Annual Production (as $LiOH \cdot H_2O$)	tpa[1]	30,000[2]
Plant Operation	years	20
Total Capital Cost (CAPEX)	US$	869,868,000[3]
Operating Cost (OPEX) per year	US$/yr	77,972,000[4]
OPEX per tonne	US$/t	2,599
Initial Selling Price	US$/t	14,500[5]
Average Annual Revenue	US$	570,076,000[6]
Discount Rate	%	8.0
Net Present Value (NPV) Pre-Tax	US$	2,830,190,000
Net Present Value (NPV) Post-Tax	US$	1,965,427,000
Internal Rate of Return (IRR) Pre-Tax	%	40.5
Internal Rate of Return (IRR) Post-Tax	%	32.1

Notes:

All model outputs are expressed on a 100% project ownership basis with no adjustments for project financing assumptions

[1] Metric tonnes (1,000 kg) per annum

[2] Total production for years 1 to 15 is 30,666 tpa LHM and 28,000 tpa LHM for years 16 to 20

[3] AACE Class 5 estimate includes 25% contingency on direct capital costs

[4] Includes all operating expenditures, ongoing land costs, established Royalties, sustaining capital and allowance for mine closure. All costs are escalated at 2% per annum

[5] Selling price of battery quality LHM based on an initial price of $14,500/t in 2021, adjusted for inflation at 2% per annum. Sensitivity analysis modelled the starting price between US$12,500-US$16,500/t.

[6] Average annual revenue over projected 20 year mine-life.

LHM battery quality pricing sensitivity assessment was completed. LHM pricing was based upon a current price of $14,500 US/tonne adjusted for inflation to the start of production in 2025. The sensitivity analysis is provided in Table 1-5 below.

Table 1-5. Lithium Hydroxide Monohydrate sale rice post-tax sensitivity analysis

LHM Price in 2021[1] (US$/t)	Post-Tax NPV (US$ Million)	Post-Tax IRR
12,500	1,544.7	27.6%
13,500	1,755.1	29.9%
14,500	1,965.4	32.1%
15,500	2,175.8	34.2%
16,500	2,386.1	36.3%

Note:
[1] 2% annual LHM price escalation from 2021 to the start of production in 2025 was applied.

1.7 Conclusions

- The total SWA Project Inferred Li-Brine Resource estimate is 1,195,000 tonnes of LCE. The volume of resources will allow the lithium bearing brine extraction operations to continue well beyond the currently assumed 20 years.
- The results of the geological evaluation and resource estimates for the PEA of SWA Project justifies development of the project to further evaluate the feasibility of production of LHM.
- The experience gained from the long-term operations of the brine extraction and processing facilities on the LANXESS controlled properties decreases the risk related to sustainability of the brine extraction from the Smackover Formation.
- Available infrastructure (roads, rail, power, etc.), qualified work force and access to Gulf Coast reagent supply will decrease the risks related to construction, and commissioning and operating of the lithium extraction and LHM processing facilities.
- The results of the bench scale testing, mini-plant and operating Demonstration Plant at LANXESS South Plant, increase the level of confidence in the key parameters for the operating cost estimate.
- Improvements made to process efficiency, particularly the reduction of reagents and chemicals consumption, will improve the economics of the SWA Project.

This preliminary economic assessment is preliminary in nature and includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves and there is no certainty that this economic assessment will be realized.

1.8 Key Study Recommendations

As per the CIM guidelines for lithium-brine, and when reporting higher level of resource classification than reported in this PEA (i.e., Indicated and Measured Brine Resources), the QP's must consider only those resources that are, or may become, recoverable under reasonably assumed technical and economic conditions. The logical next steps and work recommendations for Standard Lithium to elevate the SWA Project to a higher level of resource classification and project definition is to:

1. Collect additional brine samples from the Upper and Middle Smackover Formations either from existing wells on the SWA Property, or recomplete existing/abandoned wells or install new wells (US$1.5mm);
2. Analyse available Smackover Formation core at several locations from the Arkansas Geological Survey at 0.3 m intervals throughout the Upper and Middle Smackover Formations to assess porosity and permeability (US$0.1mm);
3. Perform long-duration pumping tests to confirm aquifer properties (US$0.9mm);
4. Complete reservoir and resource modelling (US$0.75mm);
5. Continue with ongoing direct lithium extraction pre-commercial demonstration using brines from the SWA Project (US$0.75mm);
6. Conduct lithium chloride to lithium hydroxide conversion at suitable scale (US$1.0mm);
7. Complete additional permitting and environmental studies where appropriate (US$0.5mm); and,
8. Conduct all additional necessary engineering and pre-feasibility studies to integrate the project development findings into an updated resource classification and prefeasibility study (PFS) (US$1.5mm).

The authors recommend Standard Lithium approaches accomplishing these tasks over a two year period. The total estimated cost of the recommended work including contingency is US$7,000,000.

1.9 SW Arkansas Project Related Risks and Uncertainties

As with any development project there exists potential risks and uncertainties. Standard Lithium will attempt to reduce risk/uncertainty through effective project management, engaging technical experts and developing contingency plans. With respect to access, title, or the right or ability to perform work on the property, Table 1-6 highlights some risks and uncertainties which have been identified at this stage of project development.

Table 1-6. Risk Assessment Matrix

Risk No.	Risk Description	Existing Controls	Initial Risk (after Existing Controls)	Risk Treatment Plan	Residual Risk
1	Brine production of 1,800 m^3/h and/or lithium concentration of 399 mg/L not available. Includes associated drilling risk.	A geological assessment, in addition to testing existing brine supply wells	Medium	Additional testing of existing and new brine supply wells is planned.	Low

Risk No.	Risk Description	Existing Controls	Initial Risk (after Existing Controls)	Risk Treatment Plan	Residual Risk
2	If innovative lithium extraction process does not perform as expected, could result in higher OPEX and CAPEX.	Extended pilot tests completed.	Low	Continued operation and process optimization of Demonstration Plant operation. This will also not be the first commercial plant of this type	Low
3	If electrochemical and associated Lithium Hydroxide conversion process does not perform as expected, it could result in higher OPEX and CAPEX.	Based on existing chloralkali industry technology and specific experience with Lithium solutions.	Medium	Long-term membrane testing with representative enriched LiCl solution planned, as well as pilot testing of commercial-scale electrochemical cells.	Low
4	If market price of LHM drops, project economics will be negatively affected.	Demand is increasing faster than supply is coming to the market. Sensitivity analysis shows favourable economics even for significantly lower Lithium Hydroxide price.	High	To evaluate alternate contracts with vendors to mitigate short term price decline.	High
5	Global supply chain shortages / delays could influence schedule and CAPEX	Understanding long-lead items that would be impacted by supply chain constraints	Medium	A mitigating action plan will be put in place to minimize supply chain risk.	Low
6	If natural disaster occurs (e.g., tornado, earthquake), could result in loss of production.	Understanding of current risks at plant location.	Medium	Engineering of the plant will take into account weather risks. Provide shelter for personnel. Design critical facilities to withstand moderate tornados and earthquakes. Carry special insurance.	Low
7	If unknown infringement of sorbent and process patents occurs, could result in licensing claims.	Conducted freedom to operate searches.	Medium	Continue patent research. Ensure contingency funds in place to cover licensing fees.	Low
8	Construction cost/schedule overruns	25% contingency included in current economics. Sensitivity analysis shows favourable economics even for higher CAPEX	Medium	Work with experienced EPC contractor; lump-sum turnkey where possible. PFS will provide improved cost confidence.	Low

Risk No.	Risk Description	Existing Controls	Initial Risk (after Existing Controls)	Risk Treatment Plan	Residual Risk
9	Lithium brine royalty assessment by the Arkansas Oil and Gas Commission is not completed in a timely manner and/or the royalty rates overly impact project economics.	Established process completed for bromine and most recently for calcium chloride and magnesium chloride	Medium	Work with experienced and qualified team and engage stakeholders early in the process.	Low

2 INTRODUCTION

2.1 Issuer and Purpose

This Technical Report has been commissioned by, and completed for, Standard Lithium Ltd. (Standard Lithium, or the Company); a public company with its corporate headquarters in Vancouver, B.C. Standard Lithium is focused on unlocking the lithium potential from brine. As such, Standard Lithium has established 'brine access agreements' with historically/presently permitted and active brine operators that include:

- TETRA Technologies Inc. (TETRA) and National Chloride Company of America (National Chloride) in the Mojave Desert of California (Standard Lithium's Bristol and Cadiz Dry Lakes play a Lithium-brine projects).

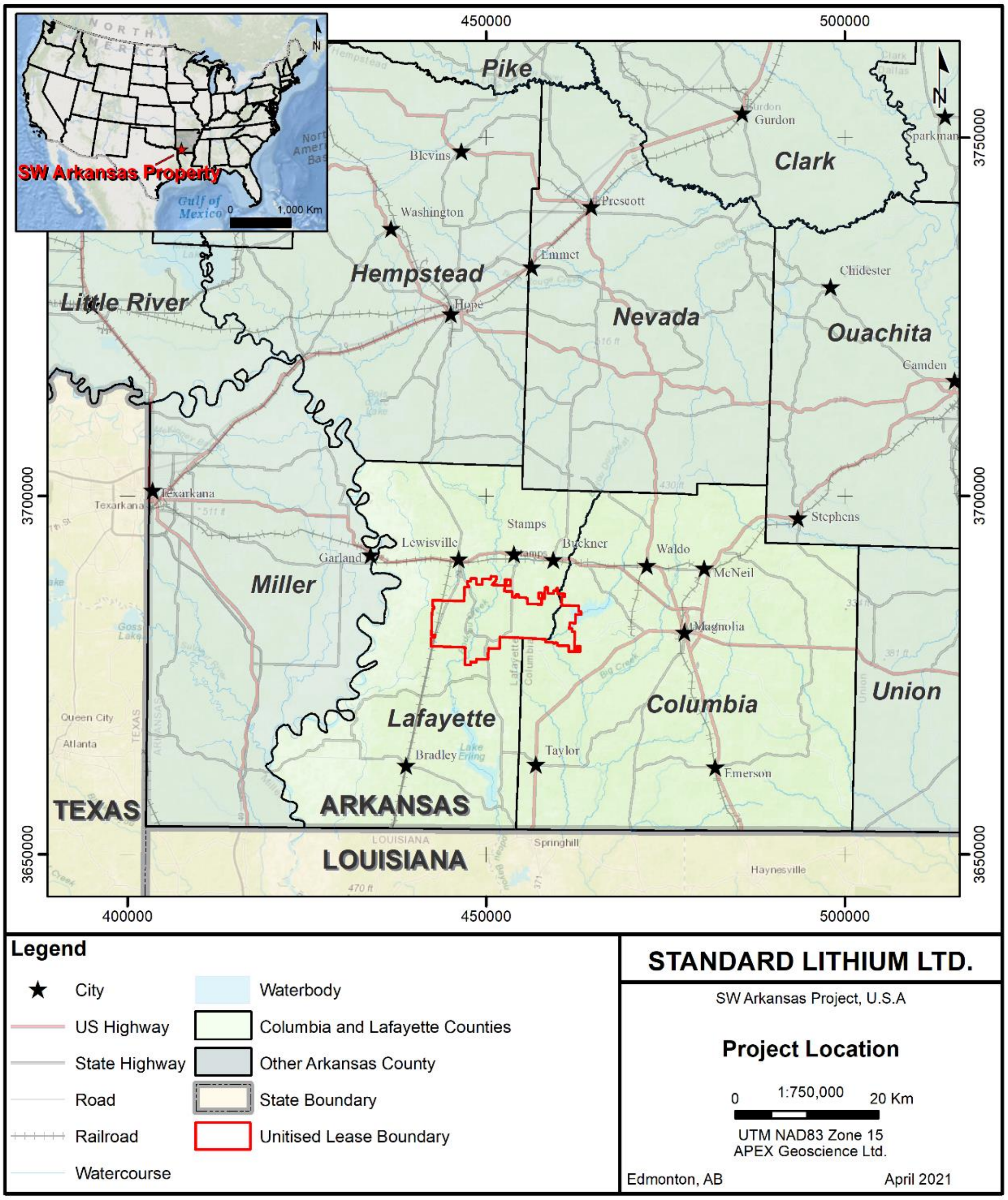
- LANXESS Corporation (LANXESS) in the Smackover Formation of south-central Arkansas (Standard Lithium's LANXESS Lithium-brine project).

- TETRA in the Smackover Formation of southwestern Arkansas (Standard Lithium's SWA Project and the focus of this Technical Report).

The centre of SWA Property is located approximately 24 km (15 miles) west of the City of Magnolia in Lafayette County, Arkansas, United States (Figure 2-1). The SWA Property encompasses Townships 16-17 South and Ranges 22-24 West of the 5th Meridian. The SWA Property comprises 802 brine leases and eight salt water (brine) deeds from private mineral owners covering 11,033 net mineral hectares (27,262 net mineral acres).

At the SWA Project, which is the focus of this report, Standard Lithium has outlined how it could unitise the underlying Smackover Formation brine aquifer in conjunction with the preparation of a PEA. This Technical Report updates the 2019 maiden Inferred Resource estimate and applies a gross acreage with 100% brine ownership that is consistent with unitisation within the Arkansas Brine Statute. This PEA also outlines a proposed method of extraction of the brine from the resource, a proposed flowsheet to extract and purify the lithium to potentially produce a marketable product, as well as other necessary SWA Project information.

Figure 2-1. General location of the SWA Project discussed in this Technical Report.



Consequently, this Technical Report provides an updated 2021 mineral resource estimate at the SWA Project in accordance with the Canadian Securities Administration’s (CSA’s) National Instrument 43-101 (NI 43-101) with the mineral resource being estimated using the CIM “Estimation of Mineral Resources and Mineral Reserves Best Practice Guidelines” dated November 29th, 2019 and the CIM “Definition Standards for Mineral Resources and Mineral Reserves” amended and adopted May 10th, 2014. The effective date of this Technical Report is November 20, 2021.

2.2 Technical Report Authors and Personal Inspection of Property

Table 2-1 presents the list of Qualified Persons (QPs) for the Technical Report and their responsibilities.

Table 2-1. Qualified Persons and their responsibilities

Report Section	Qualified Person	Company
Section 1 Summary	Tony Boyd	NORAM
Section 2 Introduction	Tony Boyd	NORAM
Section 3 Reliance on Other Experts	Tony Boyd	NORAM
Section 4 Property Description and Location	Roy Eccles	APEX Geoscience Ltd.
Section 5 Accessibility, Climate, Local Resources, Infrastructure and Physiography	Roy Eccles	APEX Geoscience Ltd.
Section 6 History	Roy Eccles	APEX Geoscience Ltd.
Section 7 Geological Setting and Mineralization	Roy Eccles	APEX Geoscience Ltd.
Section 8 Deposit Types	Roy Eccles	APEX Geoscience Ltd.
Section 9 Exploration	Roy Eccles	APEX Geoscience Ltd.
Section 10 Drilling	Roy Eccles	APEX Geoscience Ltd.
Section 11 Sample Preparation, Analyses and Security	Roy Eccles	APEX Geoscience Ltd.
Section 12 Data Verification	Roy Eccles	APEX Geoscience Ltd.
Section 13 Mineral Processing and Metallurgical Testing	Ron Molnar	METNETH2O Inc.
Section 14 Mineral Resource Estimate	Roy Eccles	APEX Geoscience Ltd.
Section 15 Mineral Reserve Estimates	N/A	N/A
Section 16 Mining Methods		
Subsections 16.1	Steve Shikaze	Matrix Solutions Inc.
Subsections 16.2 – 16.4	Trotter Hunt	HGA
Section 17 Recovery Methods	Tony Boyd	NORAM
Section 18 Infrastructure	Trotter Hunt	HGA
Section 19 Market Studies and Contracts	Tony Boyd	NORAM
Section 20 Environmental Studies, Permitting and Social or Community Impact	Rodney Breur	ECCI

Report Section	Qualified Person	Company
Section 21 Capital and Operating Costs	Trotter Hunt	HGA
Section 22 Economic Analysis	Trotter Hunt	HGA
Section 23 Adjacent Properties	Roy Eccles	APEX Geoscience Ltd.
Section 24 Other Relevant Information	Tony Boyd	NORAM
Section 25 Interpretation and Conclusions	Tony Boyd	NORAM
Section 26 Recommendations	Tony Boyd	NORAM
Section 27 References	Tony Boyd	NORAM

Note:

[1] N/A denotes not applicable.

In accordance with the CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brines (1 November 2012), this lithium-brine PEA has been prepared by a multi-disciplinary team that includes geologists, hydrogeologists, chemical, process and civil engineers with relevant experience in the lithium-brine confined aquifer type deposits, Smackover Formation geology and brine processing.

All authors are independent of Standard Lithium (and TETRA) and are QPs as defined by the CSA's NI 43-101.

Mr. Eccles P. Geol. conducted a site inspection of the SWA Property on March 5-9, 2018. The site visit validated the Property and observed active exploration at the Project in the form of using oil and gas infrastructure to obtain brine samples for analytical testing. The site inspection validated the Project's infrastructure including the primary and secondary roads, power, oil and gas wells, pipelines, and availability of highly skilled labour for brine sampling of oil and gas wells.

Mr. Trotter Hunt, P.E., visited the SWA Project proposed central processing facility site on November, 20, 2021, where the existing conditions, utilities and local infrastructure of the property were verified. The area appeared consistent with the Property descriptions detailed herein.

2.3 Sources of Information

This PEA is a compilation of publicly available information, as well as information obtained from the 2018 exploration program. The 2018 exploration program include core analysis and brine analytical test programs conducted by Standard Lithium at the SWA Property. References in this Technical Report are made to publicly available reports that were written prior to implementation of NI 43-101, including government geological publications. All reports are cited in Section 27, References.

Government reports include those that provide:

- Smackover Formation stratigraphic information;
- Arkansas policy and regulation;
- Well information;
- Produced water geochemistry; and,

- Oil, gas and brine production statistics (e.g., Dickinson, 1968; Arkansas Code, 2016; Blondes et al., 2016; Arkansas Geological Survey, 2018; AOG Commission, 2018 a to f).

Miscellaneous journal articles were used to set the geological setting of southern Arkansas (e.g., Bishop, 1967; Alkin and Graves, 1969; Bishop, 1971a and b; Buffler *et al.*, 1981; Moore and Druckman, 1981; Moore, 1984; Harris and Dodman, 1987; Salvador, 1991a and b; Troell and Robinson, 1987; Kopaska-Merkel *et al.*, 1992; Moldovanyi and Walter, 1992; Zimmerman, 1992; Heydari and Baria, 2005; Mancini *et al.*, 2008). Company information and news releases were used to reference any historical mineral exploration work at the SWA Property (e.g., Standard Lithium Ltd., 2017, 2018a, b, and c).

Roy Eccles has reviewed all government and miscellaneous reports related to Sections 7 and 8. Government reports and journal papers were prepared by a person, or persons, holding post-secondary geology or related degrees. Based on review of these documents and/or information, the author has deemed that these reports and information, to the best of his knowledge, are valid contributions to this Technical Report. Therefore, Mr. Eccles takes ownership of the ideas and values as they pertain to the current PEA.

Geochemical data collected in 2018 presented in this Technical Report were analysed at independent and accredited laboratories: ALS-Houston Environmental Services (ALS-Houston) in Houston, Texas, and Western Environmental Testing Laboratory (WetLab) in Sparks, Nevada. Historical Smackover Formation brine geochemical data from a peer reviewed journal were also used (Moldovanyi and Walter, 1992). Historical geotechnical data presented in this Technical Report include core reports that were prepared by independent petroleum engineering firms that include:

- Core Laboratories Inc. in Dallas, TX and Shreveport, LA;
- Delta Core Analysts in Shreveport, LA;
- All Points Inc. in Houston, TX;
- Thigpen Core Laboratories, Inc. in Shreveport, LA;
- O'Malley Laboratories, Inc. in Natchez, Miss; and
- Bell Core Laboratories in Shreveport, LA.

Roy Eccles has reviewed all government, manuscripts, and Company news releases, and found no significant issues or inconsistencies that would cause one to question the validity of the data. Mr. Eccles has no issue with using these data to guide the background, history, regional geology, and resource evaluation presented in this PEA (related to Sections 5, 6, 7, 14.1 – 14.9).

The laboratories and/or engineering firms are independent and certified third-party consultants and/or include certified Professional Geologists or Engineers. The geochemical laboratories for the brine samples collected in 2018 cite National and State accreditations (e.g., ISO/IEC 17025:2005; 2009 TNI Environmental Testing Laboratory Standard; DoD Environmental Laboratory Accreditation Program (DoD ELAP); ISO/IEC Guide 25-1990; NAC 445A). Historical brine analytical data originated from a peer reviewed journal (American Association of Petroleum Geologist Bulletin) and is considered a reputable source of information (Moldovanyi and Walter, 1992).

Roy Eccles has reviewed the geotechnical and geochemical data and found no significant issues or inconsistencies that would cause one to question the validity of the data (Section 12). Roy Eccles has contacted the geochemical laboratories used in the 2018 brine sampling program to discuss analytical protocols and accreditations and is satisfied the data were created using standard methodologies in the field of lithium-brine analytical work. Accordingly, Mr. Eccles has no issue using lithium concentrations provided by certified, independent laboratories and historical information in the resource estimation presented in this PEA.

2.4 Units of Measure, Currency, and Acronyms

With respect to units of measure and currency, unless otherwise stated, this Report uses:

- Abbreviated shorthand consistent with the International System of Units (International Bureau of Weights and Measures, 2006);
- 'Bulk' weight is presented in both United States short tons (tons; 2,000 lbs or 907.2 kg) and metric tonnes (tonnes; 1,000 kg or 2,204.6 lbs);
- Geographic coordinates projected in the Universal Transverse Mercator (UTM) system relative to Zone 15 of the North American Datum (NAD) 1983; and,
- Currency in Canadian dollars (CDN$), unless otherwise specified (e.g., U.S. dollars, USD$; Euros, €).
- Table 2-2 describes the various abbreviations used in the Technical Report.

Table 2-2. Abbreviations

Abbreviation	Description
μm	Micrometers
AACE	American Association of Cost Engineers
ADEQ	Arkansas Department of Environmental Quality
AOGC	Arkansas Oil and Gas Commission
APEGA	Association of Professional Engineers and Geoscientists of Alberta
ASTM	American Society for Testing and Materials
BFD	Block Flow Diagram
BOE	Basis of Estimate
Br_2	Elemental Bromine
btu/hr	British Thermal Units per hour
CAPEX	Capital Expenditure
CIM	Canadian Institute of Mining
CIT	Corporate Income Tax
CPF	Central Processing Facility
CSA	Canadian Securities Administration
DCF	Discounted Cash Flow
DEQ	Division of Environmental Quality
DLE	Direct Lithium Extraction
EA	Environmental Assessment
EGBC	Engineers & Geoscientists British Columbia
EPA	Environmental Protection Agency
ESP	Electric Submersible Pump
ESS	Energy Storage Systems
EVs	Electric Vehicles
GPM	US Gallons per Minute
H_2S	Hydrogen Sulphide
HDPE	High Density Polyethylene
ICE	Internal Combustion Engine

Abbreviation	Description
ICP-MS	Inductively Coupled Plasma Mass Spectroscopy
ICP-OES	Inductively Coupled Plasma Optical Emission Spectroscopy
IRR	Internal Rate of Return
ISBL	Inside Boundary Limit
LAS	Log ASCII Standard
LCE	Lithium Carbonate Equivalent
LHM	Lithium Hydroxide Monohydrate
Li_2CO_3	Lithium Carbonate
Li_2O	Lithium Oxide
$LiOH.H_2O$	Lithium Hydroxide Monohydrate
LPS	Large Power Service
m/se	Meters per second
m^3	Cubic Meter
MCC	Motor Control Center
mD	Millidarcies
mg/L	Milligrams per litre
MKP	McKamie-Patton
MMBTU	Million British Thermal Units
MW	Megawatts
MWh	Megawatt-hour
NAD	North American Datum
NI 43-101	National Instrument 43-101
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
OAT	One-Factor-at-a-Time
OEM	Original Equipment Manufacturers
OPEX	Operating Expenditure
PEA	Preliminary Economic Assessment
PEO	Professional Engineers Ontario
PFD	Process Flow Diagram
ppm	Parts Per Million
psi	Pounds per square inch
PSS	Pregnant Strip Solution
QA/QC	Quality Assurance/Quality Control
QP(s)	Qualified Person(s)
RCRA	Resource Conservation and Recovery Act
RO	Reverse Osmosis
ROW	Right-of-Way
RPD	Relative Percentage Difference
RSD	Relative Standard Deviation
SM	Standard Methods
TDS	Total Dissolved Solids
TEC	Total Equipment Cost
TPC	Total Plant Cost
UIC	Underground Injection Control
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
WetLab	Western Environmental Testing Laboratory

3 Reliance of Other Experts

The authors are not qualified to provide an opinion or comment on issues related to legal agreements and royalties. Roy Eccles relied entirely on background information and details regarding the nature and extent of TETRA's Land Titles (Sections 4.1 to 4.3). The author has not reviewed the approximately 802 leases and eight salt water (brine) deeds owned by TETRA or the transactional agreement between Standard Lithium and TETRA (and/or the agreement between TETRA and the underlying landowners) to obtain mineral brine production rights. The legal and survey validation of the leases and brine rights is not in our expertise and we are relying on Standard Lithium and TETRA's land-persons and lawyers.

Through personal and written communication with TETRA (Mr. Roman Wolff of TETRA; November 14, 2018), and Standard Lithium's Arkansas attorney (Mr. Robert Honea of Hardin, Jesson & Terry PLC of Fort Smith, AR; during report preparation), the author of Section 4 has no reason to question the validity or good standing of the TETRA leases and brine deeds through which Standard Lithium is gaining access to brine for process test work.

An opinion letter provided by Standard Lithium's Arkansas legal counsel, R. Christopher Lawson, P.A. (dated February 5, 2021), provided justification that 1) the Company intends to implement the Brine Statute unitisation process and 2) the unitisation of the SWA Property provides the most efficient pathway for the production process by protecting the production rights of the brine operator and the correlative rights of mineral interest owners.

The QP of Section 4 relied on Standard Lithium's management and legal representation with respect to the details of the brine option agreement summarized in Section 4.2. This information was detailed in a press release by Standard Lithium (Standard Lithium Ltd., 2018a).

The QP of Section 4 has tried to adequately summarise the detail of the option agreement for the reader, but in doing so, have simplified the legal language such that it might not be on par with full legal definition.

The QP of Section 4 relied on verbal information provided by Standard Lithium management regarding permitting and environmental status of the Property. This information was provided by Standard Lithium during the preparation of the report and is summarised to the best of the author's knowledge in Section 4.5.

4 PROPERTY DESCRIPTION AND LOCATION

4.1 Property Description and Location

The SWA Property encompasses Townships 16-17 South and Ranges 22-24 West of the 5th Meridian. The centre of SWA Project is located approximately 24 km (15 miles) west of the City of Magnolia in Lafayette and Columbia Counties, Arkansas, United States. Coordinates for the Property centre are:

- Latitude 33.2843 and Longitude -93.5135; or
- Universal Transverse Mercator 452185.15 Easting, 3682922.78 Northing, Zone 15N, North American Datum 83 (Figure 2.1).

The SWA Property consists of 11,033 net mineral hectares (27,262 net mineral acres) and covers about 110 km^2 (42 square miles) and is comprised of 489 land tracts containing 802 individual leases and 8 salt water (brine) deeds from private mineral owners, as illustrated in Figure 4.1. The proposed unitised area encompasses the individual leases and consists of 14,638 gross mineral hectares (36,172 gross mineral acres).

4.2 Lithium-Brine Mineral Production Rights

The SWA Project consists of mineral brine production rights conveyed in 802 leases and eight salt water (brine) deeds. The mineral brine rights for the leases and deeds are composed of a composite of properties totaling 11,033 net mineral hectares (27,262 net mineral acres) within the entire SWA Property envelope of 14,638 hectares (36,172 acres).

Standard Lithium acquired the SWA Project brine rights to produce lithium from TETRA through an option agreement. As part of the agreement between Standard Lithium and TETRA, Standard Lithium owns the ‘Lithium-brine’ production rights within the SWA Property brine lease holding. The Standard Lithium-TETRA agreement and a summary of the leases and deeds are discussed in more detail in following sub-sections.

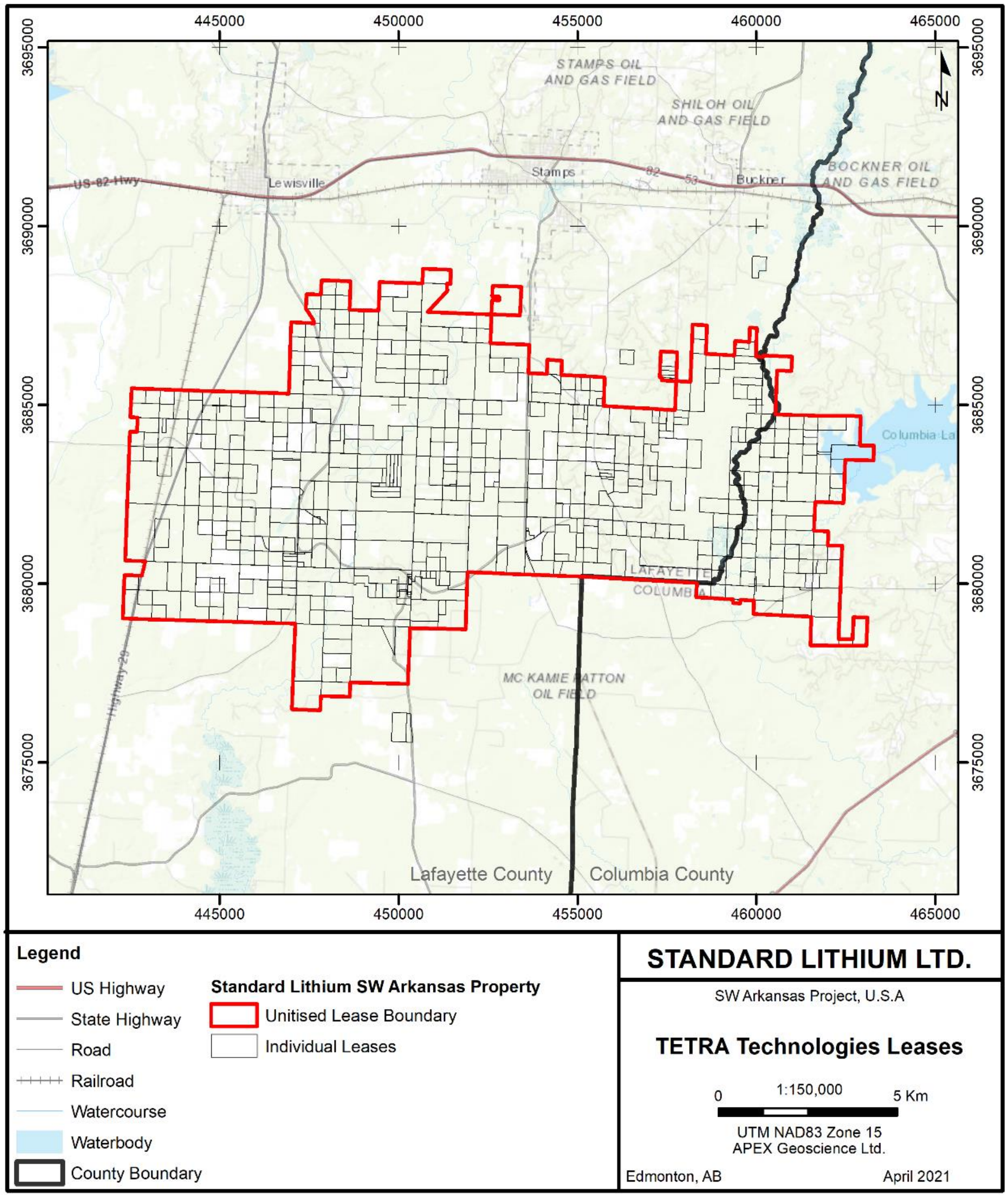
4.2.1 Summary of the Standard Lithium – TETRA Agreement

Standard Lithium owns the rights to produce lithium from TETRA’s brine leasehold for a period of 10-years (the exploratory period) through an option agreement providing that Standard Lithium makes annual payments on the annual anniversary of the effective date (December 29, 2017) of the agreement with TETRA, as follows:

- US$500,000 before January 28, 2018 (paid)
- An additional US$600,000 on or before December 29, 2018 (paid)
- An additional US$700,000 on or before December 29, 2019 (paid)
- An additional US$750,000 on or before December 29, 2020 (paid)
- Years 4-10: $1,000,000 per year

When Standard Lithium commences production of lithium, the option agreement is converted into production and Standard Lithium will pay TETRA a 2.5% royalty on gross revenue, and not less than $1,000,000 in any year, starting on the date that Standard Lithium exercises the option, or after the expiration of the 10-year exploratory period.

Figure 4-1. SWA Project discussed in this Technical Report.



4.2.2 Summary of Eight Salt Water (Brine) Deeds

In 1992, TETRA acquired the rights to 2,045 acres in the form of eight salt water (Brine) Deeds. The brine deeds are a 35-year term conveyance of brine within the Smackover Formation limestone. The initial brine deeds were executed from March 23 to April 29, 1992 and will expire in 2027 unless the term is extended by agreement.

The Brine Deeds permit TETRA or its assignee to produce brine attributable to its Grantor's interest in the covered lands without royalty becoming due. Thus, with respect to those Grantors' brine interests, no delay rental or brine royalty payment is required, and no additional royalty will become due upon commercial extraction of lithium. Instead, TETRA is obligated to make annual promissory note installment payments of $79,125, in the aggregate, on promissory notes executed by TETRA in favor of the Grantor and its related parties. These notes provide for 35 annual installments, coinciding with the term of the Brine Deed.

4.2.3 Summary of 802 Leases

In 1994, TETRA implemented a brine leasing strategy and added additional brine leases in 2006 and 2017-2018 bringing their total lease holdings to 802 leases at the Effective Date of this Technical Report. Except for three (3) leases with five-year terms dated 26 September 2018, representing 240 acres, each lease has a 25-year term and the leases are being renewed prior to the expiration of the original 25-year term. The SWA Property brine leases have yet to be developed for production of brine minerals.

4.2.4 Mineral Brine Right Distribution on Individual Leases

In some instances, the property encompassed by an individual brine lease may be very small, less than one hectare, or much larger, up to several hundred hectares. The percentage of brine rights ownership varies from section to section. In some instances, the percentage of the area leased within an individual brine lease may be small, less than 10%, or up to 100% ownership within any arbitrary section.

Overall, the lease ownership is complex, however, Standard Lithium has conducted a due diligent compilation of the percentage ownership of the individual brine leases on a section-by-section basis. That is, Standard Lithium engaged third-party firm R&J Land Services, LLC (R&J Land) of Bossier City, Louisiana to conduct due diligence of TETRA title of the brine leases and salt water (brine) deeds.

Standard Lithium also retained Arkansas attorney, Mr. Robert Honea, of Hardin, Jesson & Terry PLC of Fort Smith, AR regarded as having expertise in Arkansas State brine as well as oil and gas law. Mr. Honea issued an opinion letter to Standard Lithium, prior to Standard Lithium signing the Option Agreement with TETRA, after reviewing R&J Land's review into the documentation of title to TETRA leasehold, confirming his professional opinion that the title due diligence performed by R&J Land was reasonable.

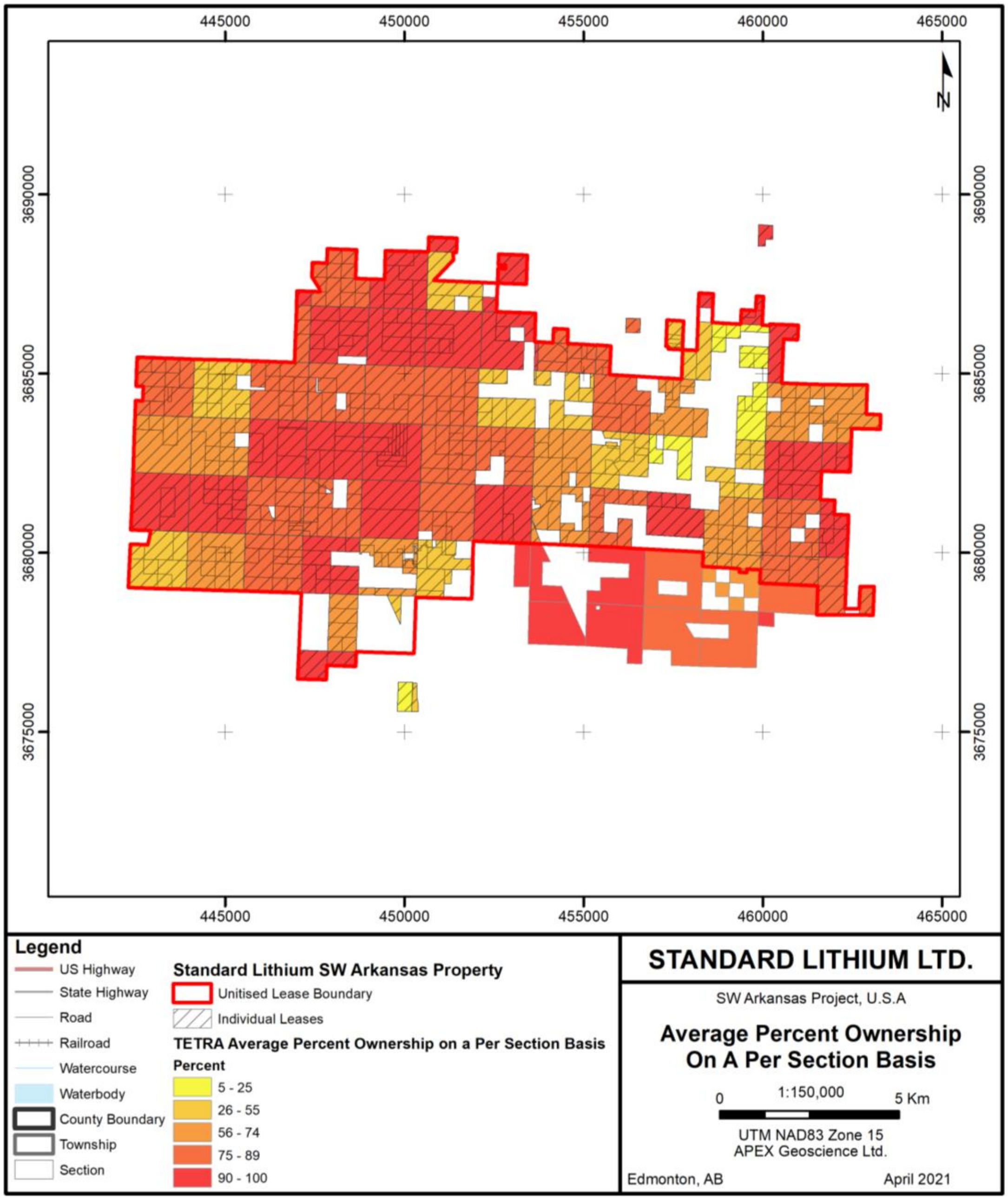
Standard Lithium previously engaged Mr. Christopher Lawson, an Arkansas lawyer who specialised in brine law as its outside counsel, and received Mr. Lawson's confirmation that after reviewing Standard Lithium's documentation of the title due diligence, the net acreage total represented by the title to validated leases appeared to be in good-standing. Prior to the publication of this Technical Report, Mr. Lawson passed away, and the role of outside counsel with respect to Arkansas brine statutes has been taken up by Mr. Robert Honea.

The resulting section-based mineral brine lease percentage compilation is presented in Table 4-1 and Figure 4-2. To simplify the brine ownership for the purpose of reporting, TETRA has amassed a mineral brine rights ownership that encompasses approximately 74% of the total mineral brine rights at the SWA Property, of which, Standard Lithium has acquired the corresponding Li-brine production rights as described in Section 4.2, Lithium Brine Mineral Production Rights.

Table 4-1. SWA Property ownership summary

Township	Range	Section	Net Acres Leased	Total Gross Acres within Section[1]	Percentage Leased	Township	Range	Section	Net Acres Leased	Total Gross Acres within Section[1]	Percentage Leased
16	22	31	37.815	200	19%	17	23	10	308.19	640	48%
16	23	19	80	80	100%	17	23	11	140	640	22%
16	23	24	40	50	80%	17	23	12	315	640	49%
16	23	25	80	80	100%	17	23	13	450	640	70%
16	23	26	20	80	25%	17	23	14	573.8	600	96%
16	23	29	192.5	195	99%	17	23	15	368.32	478.32	77%
16	23	30	213.84	516.34	41%	17	23	16	409.38	640	64%
16	23	31	610	640	95%	17	23	17	585.46	640	91%
16	23	32	511.67	545	94%	17	23	18	570.83	640	89%
16	23	33	278.83	335.36	83%	17	23	19	207.497	640	32%
16	23	34	255.33	296.6	86%	17	23	24	125	165	76%
16	23	35	192.58	499.33	39%	17	23	31	14.92	40	37%
16	23	36	160	640	25%	17	24	1	561.489	640	88%
16	24	25	586.66	640	92%	17	24	2	551.134	640	86%
16	24	26	566.71	640	89%	17	24	3	525.491	640	82%
16	24	27	36.67	40	92%	17	24	4	498.78	640	78%
16	24	34	136.67	160	85%	17	24	5	562.46	640	88%
16	24	35	593.68	640	93%	17	24	8	397.95	640	62%
16	24	36	613.33	640	96%	17	24	9	461.46	640	72%
17	22	5	407.5	640	64%	17	24	10	594.76	640	93%
17	22	6	473.92	640	74%	17	24	11	627.58	640	98%
17	22	7	640	640	100%	17	24	12	623.87	640	97%
17	22	8	160	160	100%	17	24	13	638	638	100%
17	22	17	276	280	99%	17	24	14	525.48	640	82%
17	22	18	560	640	88%	17	24	15	535.78	640	84%
17	22	19	320.5	320.5	100%	17	24	16	600	640	94%
17	22	20	357.5	400	89%	17	24	17	640	640	100%
17	23	1	31.27	640	5%	17	24	20	290.846	640	45%
17	23	2	405	640	63%	17	24	21	446.53	640	70%
17	23	3	556.92	640	87%	17	24	22	498	640	78%
17	23	4	270.64	640	42%	17	24	23	614.3	640	96%
17	23	5	351.5	640	55%	17	24	24	452.71	640	71%
17	23	6	554.17	640	87%	17	24	25	20	40	50%
17	23	7	498.83	640	78%	17	24	26	206.39	320	64%
17	23	8	541.04	640	85%	17	24	35	240	240	100%
17	23	9	429.51	640	67%	17	24	36	40	640	6%
		Total	12,040.59	16,398.13				Total	15,221.407	20,441.32	

Figure 4-2. SWA Property ownership summary



4.3 Surface (and Mineral) Rights in Arkansas

The definition of minerals is established by Arkansas Code Title 15, Natural Resources and Economic Development § 15-56-301 (the Brine Statue), which has been amended to include salt water, or brine, "*whose naturally dissolved components or solutes are used as a source of raw material for Bromine and other products derived therefrom*." The mineral interest owner has the inherent right to develop the minerals and the right to lease the minerals to others for development. When a company desires to develop the mineral resources in an area, the company will need to secure mineral lease agreements from the mineral owners. The mineral lease is a legal binding contract between the mineral owner (Lessor) and an individual or company (Lessee), which allows for the exploration and extraction of the minerals covered under the lease.

Payments made to the Lessor for production of brine are known as “in lieu” royalty payments because the payments are made annually based on a statutory rate, as opposed to a true royalty based on the amount of the produced brine. The statutory in lieu royalty payment is increased or decreased annually based on changes in the Producer Price Index.

The Brine Deeds permit TETRA or its assignee to produce brine attributable to its Grantor’s interest in the covered lands without royalty becoming due. Thus, with respect to those Grantors’ brine interests, no delay rental or brine royalty payment is required, and no additional royalty will become due upon commercial extraction of Lithium. Instead, TETRA is obligated to make annual promissory note installment payments of $79,125, in the aggregate, on promissory notes executed by TETRA in favor of the Grantor and its related parties. These notes provide for 35 annual installments, coinciding with the term of the Brine Deed. TETRA is also required to pay annual rental of $100 each to the two surface owners who leased the surface right of ingress and egress to TETRA in documents called “Landowner Agreements.”

With respect to surface rights, Arkansas law allows the severance of the surface estate from the mineral estate by proper grant or reservation, thereby creating separate estates. Under the laws of conservation in the State of Arkansas, however, the mineral rights are dominant over the surface rights. In some cases, when the mineral owner leases the right to produce oil, gas and/or brine, the Lessee succeeds to the mineral owner’s right of surface use, subject to lease restrictions. Authority of the mineral estate over the surface is a crucial legal concept for the mineral owner and Lessee because ownership of subsurface minerals without the right to use the surface to explore for and produce them would be practically worthless. If a Lessor does not want the land surface disturbed a “No Surface Operations Clause” may be negotiated with the Lessee and included in the mineral Lease agreement. This clause may be used to limit or restrict the use of the property for drilling activity or long-term production operations. Conflicts arising between the Lessee and surface owner can be avoided by creating Lease agreements that clearly identify the scope of surface use rights.

The Lessee holding the Lease has a legal authority to enter the property for exploration and production even if the non-mineral owning surface owner objects to the intrusion on the property. That does not mean the surface owner will be without compensation. The amount and type of compensation is strictly a matter of negotiation between the surface owner and the company entering the property. If mutual agreement cannot be reached, the surface owner always has the right to seek the advice of an attorney and relief through the court system.

In the State of Arkansas when a person sells a piece of property the mineral rights automatically transfer with the surface rights, unless otherwise stated in the deed.

4.4 Unitisation

The Arkansas Brine Statute (AR Code § 15-76-301) was adopted by the Arkansas General Assembly in 1979 in response to expanding brine operations in southern Arkansas. Under the statute, the AOGC can authorise brine production units that contain one or more production/injection wells within a set amount of acreage to 1) provide a more efficient regulatory structure for the production of brine, 2) to protect the correlative rights of all mineral interest owners in the unit, and 3) to insulate brine operators from claims of trespass from adjacent mineral interest owners. Under the Brine Statute, brine owners are paid an annual amount known as an “in lieu royalty” based on a specific formula in the Brine Statute which is subject to annual adjustments under the applicable Producer Price Index.

Standard Lithium has contemplated how it might approach unitising the underlying Smackover Formation brine aquifer in conjunction with the preparation of this PEA report. The unitised SWA Property encompasses 14,638 gross mineral hectares (36,172 gross mineral acres) and forms the updated resource and project area.

NOTE, Standard Lithium has **NOT** commenced the unitisation process; the exercise described herein is an attempt to estimate the potential integrated lithium brine resource if Standard Lithium’s existing project leasehold area were to be unitised in the future for production, as it would need to be.

In order to unitise a contiguous area of acreage for brine production, the brine operator must file an application with the Commission supported by the following evidence:

- A description of the proposed brine unit.
- A proposed plan of development and operation.
- Geological and engineering data supporting the feasibility of the proposed plan and the efficacy of the boundary lines of the proposed unit.
- A plat of the proposed unit indicating the tracts or parcels included in the unit and the proposed location of production and injection wells.
- A list of owners within the unit.
- Evidence that the applicant has valid brine leases covering at least 75% of the net mineral acreage within the entire area of the unit.
- Evidence that the operator has made reasonable efforts to lease all of the acreage within the proposed unit.

4.5 Potential Future Royalty Payments to Lessors

The AOGC, in accordance with Arkansas law, has established ‘drilling units’ that consist of a set amount of acreage to protect correlative rights and ensure all mineral owners receive proper payment of production royalties (in the case of oil and gas production), and statutory in lieu royalty payments (in the case of brine production). Given that future brine production from the Project would be derived from a common aquifer in the Smackover Formation, the establishment of a unit(s) with defined boundaries would ensure that all mineral owners potentially impacted by the producing well(s) would receive proper compensation.

The AOGC was given the jurisdiction and authority to form brine production units in Ark. Code §§ 15-76-301 *et seq*. (the Brine Statute). The AOGC's rules and regulations are available on-line at: www.aogc.state.ar.us/ along with its hearing schedule and production data from 1992 forward. Pertinent provisions of the Brine Statute include:

- §15-76-308 which identifies who may make application for the establishment of brine production units and states that a brine production unit may consist of no fewer that 1,280 contiguous surface acres (Arkansas Code, 2016a);
- §15-76-309 which prescribes what information must be provided in a petition to form a brine production unit (Arkansas Code, 2016b);

- §15-76-312 which permits the owner of an interest in a tract of land that is adjacent to a brine production unit and is not included in the unit, to petition for inclusion within the unit (Arkansas Code, 2016c);
- §15-76-314 which requires each owner of an unleased interest in an established production unit to elect within 60 days from the effective date of the order to either participate affirmatively in the operation or to transfer his interest in the brine to the participating producers; and
- § 15-76-315, which provides as follows:

  (c) (1) In addition to any other amounts due and owing by the producer or producers of any unit to the owners therein, the producer or producers shall account separately and on a fair and equitable basis to each owner in the unit for all substances which are found by the commission to be profitably extracted from brine by a producer and which were not extracted by a producer on January 1, 1979.

  (2) Whether or not any such substance is extracted profitably shall be determined by the Oil and Gas Commission on the basis of the value at the time of extraction, without interest, after deducting all costs of producing and recovering the same.

It is the expectation of the AOGC that entities desiring to drill and operate an oil, gas or brine well in Arkansas will attempt in good faith to negotiate a satisfactory mineral lease with mineral owners before resorting to the integration provisions of Arkansas law. In the case of brine production, the operator will negotiate a per acre bonus consideration to be paid upon signing of the lease. Under the Brine Statute, the AOGC will approve a unit for a brine operator when the operator files an application supported by the elements described in Section 4.3.1.

Moreover, pursuant to Ark. Code Ann. § 15-76-315(c) (as quoted above), the AOGC must approve the royalty rate for any “additional substance” profitably extracted from brine produced by an operator of a brine unit.

4.6 Property Environmental Liabilities and Permitting

Environmental and cultural impact studies pertaining to the possible future extraction of the Smackover Formation brine resource on the SWA Project are presented in Section 20.

Several Federal and State permits, and approvals are required for brine production in Arkansas, for example:

- U.S. Environmental Protection Agency and the AOGC – Underground Injection Control Permit and the Clean Air Act;
- AOGC – Operating Agreement; Arkansas Department of Environmental Quality (ADEQ) – Operating Air Permit; and
- Arkansas Department of Pollution Control and Ecology – Arkansas Water and Air Pollution Control Act.

Currently there is no brine production occurring on the SWA Project for the express purpose of mineral extraction. Brine is produced from the Smackover Formation across and immediately adjacent to the Property as a normal part of oil and gas extraction operations, but any brine produced is removed and disposed of as per normal oilfield activities.

If Smackover Formation brine from the SWA Project is to be used in the future for process testing work, some on-site pre-treatment may be required to remove dissolved hydrogen sulphide (H_2S), and all necessary permitting should be implemented accordingly.

4.7 Risks and Uncertainties

As with any development project there exists potential risks and uncertainties. Standard Lithium will attempt to reduce risk/uncertainty through effective project management, engaging technical experts and developing contingency plans.

The following risks and uncertainties have been identified at this stage of project development:

- Lithium brine royalty assessment by the AOGC is not completed in a timely manner and/or the royalty rates overly impact project economics.
- Brine access at the SWA Property is currently dependent on petroleum operators; hence there is a risk that the oil and gas companies will shut down well production due to poor oil/gas recovery. Standard Lithium would then have options such as purchasing the well, renting the operation of the well, or drilling new wells as appropriate etc. With respect to unitisation, it is possible that the AOGC recommends changes to the outline of the proposed unit area used in this Technical Report, which would influence the area of resource estimation.
- Unitisation in-lieu royalty payments, which are meant to be to fair and equitable as determined by the Commission, are subject to annual adjustments under the applicable Producer Price Index and such changes may influence the preliminary economics of the project.

5 Accessibility, Climate, Local Resources, Infrastructure and Physiography

The SWA Project has an extensive all-season secondary road network. Access is provided by U.S. and Arkansas state highways. U.S. Highway 82 links the cities of Lewisville, Stamps and Magnolia, running west-to-east, and U.S. Highway 371 runs just southeast of the Property (Figure 5-1). Arkansas State Highways 29, 53, 313 and several improved county roads provide access to every section of the Property.

The nearest airport is Magnolia Municipal Airport, located immediately to the east of the SWA Project, and approximately 5 km (3 miles) south-east of Magnolia in Columbia County. In addition, there are two airports, one commercial and a small general aviation airport, located in Union County near the city of El Dorado. El Dorado is approximately 55 km (34 miles) east of Magnolia.

Oil and gas extraction related infrastructure are present across the SWA Project area, particularly in the northern and southern parts of the Property. This infrastructure consists of wellheads, collection facilities for various fluids, batteries, gas processing plants and associated pipelines and cleared easements. Much of the infrastructure is variably in use by junior operators, and the operation thereof can be cyclical depending on hydrocarbon market conditions (for example, the McKamie Patton gas processing plant though potentially fully functional, is currently under ‘care and maintenance’ operation).

The project area climate is generally humid with average temperature and precipitation of 23.6 ºC (74.4 ºF) and 126.7 cm, respectively (49.8 inches; Figure 5-2). Annual rainfall is evenly distributed throughout the year. The wettest month of the year is June with an average rainfall of 11.7 cm (4.6 inches). Temperatures in Magnolia during summer tend to be in the 30’s ºC (90's ºF), and cool during winter when temperatures tend to be in the 10’s ºC (50's ºF). The warmest month of the year is July with an average maximum temperature of 34 ºC (93 ºF), while the coldest month of the year is January with an average minimum temperature of -2 ºC (30 ºF).

Lafayette County has a total area of 1,430 km^2 (545 square miles), of which 1,386 km^2 is land-based (528 square miles) and 44 km^2 is water-based (17 square miles). Columbia County has a total area of 1,996 km^2 (767 square miles), of which 1,984 km^2 is land-based (766 square miles), and 12 km^2 is water-based (0.7 square miles).

In Arkansas, the West Gulf Coastal Plain covers the southern portions of the state along the border of Louisiana. This Lowland area of Arkansas is characterized by pine forests and farmlands. Natural resources include natural gas, petroleum deposits and bromine-rich brine resources. The lowest point in the state is found on the Ouachita River approximate 90 km (56 miles) east of the Property in the West Gulf Coastal Plain of Arkansas.

Figure 5-1. SWA Property with cities/towns and access routes, including major and secondary U.S. highways and railway lines.

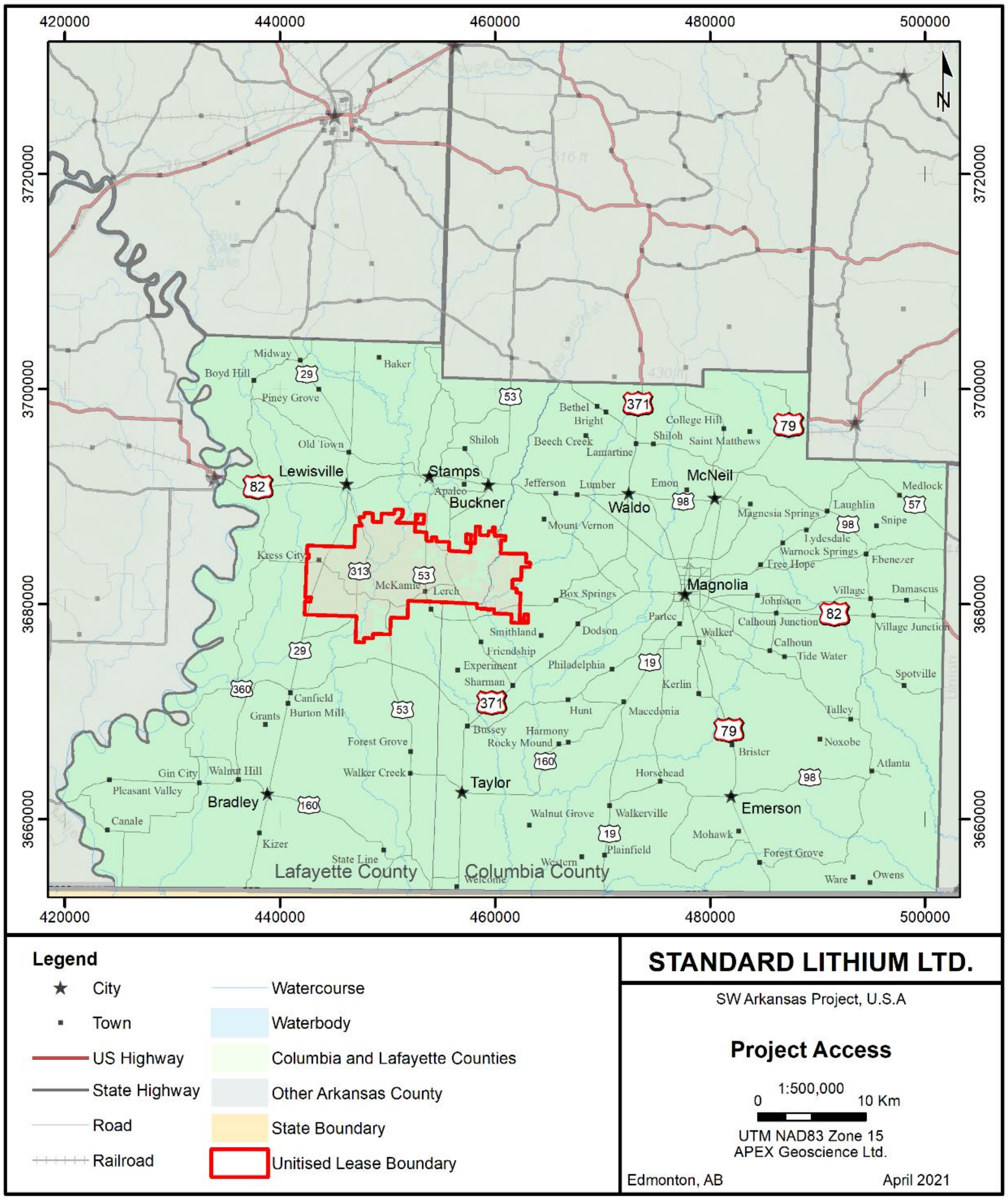
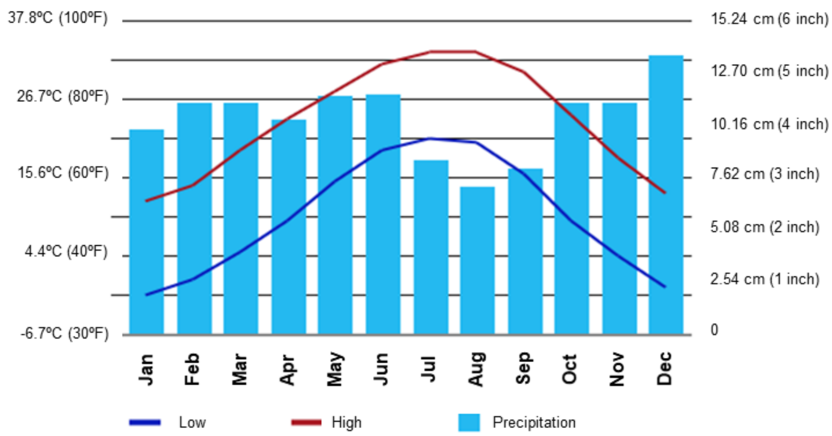


Figure 5-2. Average temperature and precipitation at Magnolia, AR.



The terrain consists of rolling hills with large timber farms and is sparsely populated by rural private residences. The largest nearby city is Magnolia, located about 22 km (15 miles) to the east. Magnolia is the County Seat of Columbia County and has a population of approximately 11,500. Magnolia is also the location of the main campus for the Southern Arkansas University and houses a student population of approximately 4,600. The combined population of Lafayette and Columbia Counties is estimated at approximately 31,000 based on census data from 2010.

6 HISTORY

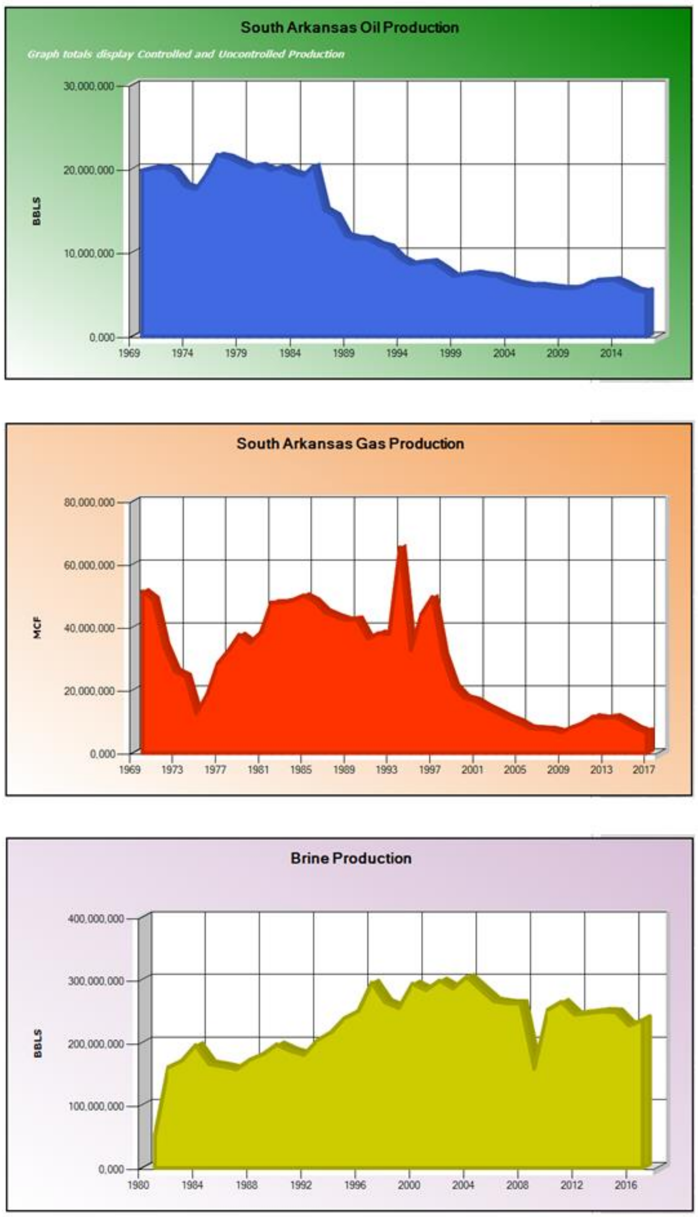
6.1 Introduction to Brine Production in Arkansas

On January 10, 1921 Dr. Samuel T. Busey discovered oil in southern Arkansas with the completion of the well Busey No. 1 about 1.6 km (1 mile) south of the City of El Dorado, AR. The discovery led to an oil boom that attracted thousands of explorers and workers. By 1923, the petroleum region had attracted 59 oil contracting companies, 13 oil distributors and refiners and 22 oil production companies (The Encyclopedia of Arkansas History & Culture). During World War II, El Dorado became a focal point for several chemical and munitions plants, most of which closed shortly after the war. Oil, chemical, and timber interests continue to play a powerful role in the local economy.

Since the mid-1980s (oil) and early 2000s (gas), the hydrocarbon industry has been in a steady state of decline in southern Arkansas. Conversely, brine production steadily increased during the 1980s with consistent production to the present (Figure 6-1). These trends are in large part due to dwindling petroleum reserves within the Smackover Formation reservoirs, which as they mature, produce more brine than hydrocarbon (Figure 6-1). Brine production has continued due to the important realisation that the brine contained elements of interest (i.e., bromine).

When oil was first discovered in south Arkansas, the brine was considered a worthless by-product of drilling/pumping. Industry realised, however, that the Smackover Formation aquifer brine contained elevated elements such as bromine in addition to hydrocarbon (e.g., 3,000-5,000 mg/L bromine; versus 65 mg/L in seawater; Mills et al., 2015; USGS, 2016). Accordingly, the commercial potential of bromine-brine gradually became apparent (McCoy, 2014).

Figure 6-1. Summary of south Arkansas oil, gas and brine production (1960s up to 2017). Source: AOGC (July 3, 2018).



Bromine is one of two elements that are liquid at room temperature and is found principally as a dissolved species in seawater, evaporitic (salt) lakes, and underground brine. The primary uses for bromine compounds include brominated flame retardants, intermediates and industrial uses, drilling fluids, and water treatment.

According to brine production records maintained by the AOGC, Union and Columbia County's 2017 brine production was 236 million barrels (37.5 million m^3) (Table 6-1). No brine production, based upon AOGC information, was identified from Lafayette County or within the boundaries of the SWA Property, though it is known to occur as a by-product ('produced water') of oil and gas extraction in the SWA Project area.

Table 6-1. Southern Arkansas 2017 brine production (US Barrels). Source: AOG Commission.

Field	County	2017 Production (U.S. Barrels)	Cumulative Production (1979-2017; U.S. Barrels)
ATLANTA	Columbia	4,031,068	116,873,573
BIG CREEK	Columbia	2,283,859	104,853,461
BURNS POND	Union	10,558,813	208,275,556
CAIRO	Union	6,451,669	337,407,996
CATESVILLE	Union	23,071,993	1,015,085,713
HIBANK	Union	11,043,766	240,589,321
HOGG	Columbia	3,173,086	60,394,390
KERLIN	Columbia	3,334,437	721,531,613
KILGORE LODGE	Columbia	34,155,209	1,282,438,515
LISBON	Union	8,950,522	327,965,505
MAGNOLIA	Columbia	6,837,463	139,826,117
MARYSVILLE	Union	42,543,820	959,062,930
SCHULER EAST	Union	4,252,332	168,143,975
VILLAGE	Columbia	47,359,049	565,577,752
WARNOCK SPRINGS	Columbia	17,298,649	476,448,432
WILKS	Union	10,620,072	935,963,963
		235,965,807	**7,660,438,812**
	Union	117,492,987	4,192,494,959
	Columbia	118,472,820	3,467,943,853

Based upon a review of the AOGC database no brine production was available for the Mars Hill, Kress City, McKamie NE, Liberty Church or Lewisville oil and gas fields within the SWA Property.

Brine production information is available along with Smackover Formation oil and gas production for the McKamie-Patton field, which is immediately adjacent to the south of the Property. Table 6-2 summarizes production from six (6) wells that are producing from the Smackover Formation with total brine production from 2013 to March 2018 of 4,123 m^3 (25,930 bbls)

The QP has been unable to verify AOGC brine production information specifically related to the SWA Property and therefore the analogy of brine production in neighboring counties or oilfields is not necessarily indicative of potential brine production within the SWA Property. Having said this, Standard Lithium was able to sample brine from wells on the Property and the Company conducted a hydrogeological characterisation of the Project area. The reader is directed to Sections 10, Exploration and 14.5, Hydrogeological Characterisation to review this information as it relates to brine potential at the SWA Property.

Table 6-2. Oil, gas and brine production for McKamie-Patton Smackover Formation wells from 2013 to March 2018. Source: Mission Creek Resources, LLC.

Well name	Days on	Oil production (m^3)	Gas production (m^3)	Water production (m^3)	Water / Oil (%)	Water cut (%)
McKamie Patton A Unit 2	1,933	806	2,531,567	365	45.3	31.2
McKamie Patton A Unit 3	1,842	504	1,853,149	233	46.2	31.6
McKamie Patton A Unit 12	227	118	218,562	52	44.4	30.8
McKamie Patton A Unit 9	1,947	473	1,622,595	212	44.9	31.0
McKamie Patton A Unit 8	1,946	6,963	23,235,671	3,210	46.1	31.6
McKamie Patton A Unit 33	832	117	321,787	51	43.5	30.3
	Average	1,497	4,963,889	687	45	31

6.2 Regional Assessment of the Lithium Potential of the Smackover Formation Brine (Discussion Extends Beyond the Boundary of the SWA Property)

This sub-section discusses Li-brine that extends beyond the boundary of the SWA Property. The issuer and the QP disclaim adjacent property information as being not necessarily indicative of the mineralisation on the SWA Property.

Brine aquifers have different characteristics than, for example, traditional mineral deposits such as precious and base metal deposits. Any given aquifer can have enormous sub-surface dimensions, and therefore, the scale of the Smackover Formation aquifer is important background information to relate to the reader. The best way to do this is to provide discussion on the nature and extent of lithium brine potential of the Smackover Formation.

The United States Geological Survey (USGS) National Produced Waters Geochemical Database v2.2, contains geochemical information from wellheads across the U.S. The database includes 165,960 produced water samples that were collected between 1886 and 2013 (Blondes et al., 2016). In addition to the major element data, the database contains trace element, isotope, and time-series data that provide spatial coverage for specific formations and/or aquifers. Quality control of the database must be performed by culling the data based on geochemical criteria (Blondes et al., 2016); however, the authors have not filtered any data and include lithium-brine results directly from the USGS National Produced Waters Geochemical Database.

The USGS National Produced Waters Geochemical Database was searched for lithium-enriched brine specifically identified within: “Smackover”, “Upper Smackover” or “Reynolds Member” of the Smackover Formation. The search was contained throughout southern Arkansas within Union, Columbia and Lafayette Counties and the results are summarized in Figure 6-2. The highest recorded Lithium brine in this USGS-compiled database occurs within the LANXESS Property (1,700 mg/L) followed by a sample with 1,430 mg/L in Columbia County (approximately 5 km north east of the SWA Property) and 740 mg/L in northern Union County. Brine analyses with lithium values between 300 and 500 mg/L occur predominantly in Columbia County with a single recorded sample in Lafayette County located on the SWA Property. Brine containing 100 to 300 mg/L of lithium occurs across all three counties.

The brine geochemical data collected from the Moldovanyi and Walter (1992) study are included in the USGS National Produced Waters Geochemical Database. This was a regional brine chemical study that collected and analysed Smackover Formation brine samples from 87 wells producing from 45 reservoirs in southwest Arkansas, east Texas, and northern Louisiana. The study allowed these authors to hypothesize/conclude the following points with respect to the regional distribution of the elevated Smackover Formation lithium brine:

- Boron and alkali metal (lithium, potassium, and rubidium) concentrations in Smackover Formation waters exhibit coherent geochemical relations across the southwest Arkansas shelf;
- In general, the concentration of these elements is greater and more heterogeneous in hydrogen sulfide-rich (H_2S) brine than in hydrogen sulfide-free waters (see the authors' hydrogen sulfide-rich polygon on Figure 6-2); and,
- Regional concentration gradients in hydrogen sulfide, boron, lithium, potassium, and rubidium suggest fluids enriched in these elements may have migrated into the Smackover Formation reservoirs from large-scale circulation of deep-seated waters along segments of the South Arkansas and Louisiana State Line graben fault system (Moldovanyi and Walter, 1992).

With respect to the SWA Project, the Moldovanyi and Walter (1992) dataset includes four brine analyses within the boundaries of the Property (Figure 6-3). The brine contained lithium from 132 mg/L (Purser 2) to 432 mg/L (Cornelius 2). Based on these data, the brine in the southern portion of the Property contains higher levels of lithium in comparison to the northern portion of the Property.

The brine from the northern portion of the Property contains 132 mg/L (Purser 2) to 187 mg/L (Haberyan 1) of lithium for an average of 160 mg/L. Historical brine samples collected from the southern portion of the Property ranged from 370 mg/L (Cornelius 2) to 423 mg/L (Cornelius 1) lithium with an average of 397 mg/L.

Figure 6-2. Regional Smackover Formation lithium-brine values from the USGS National Produced Waters Geochemical Database. Source: USGS National Produced Waters Geochemical Database (from Blondes et al., 2016). The H_2S-rich belt and fault zones are from Moldovanyi and Walter,1992.

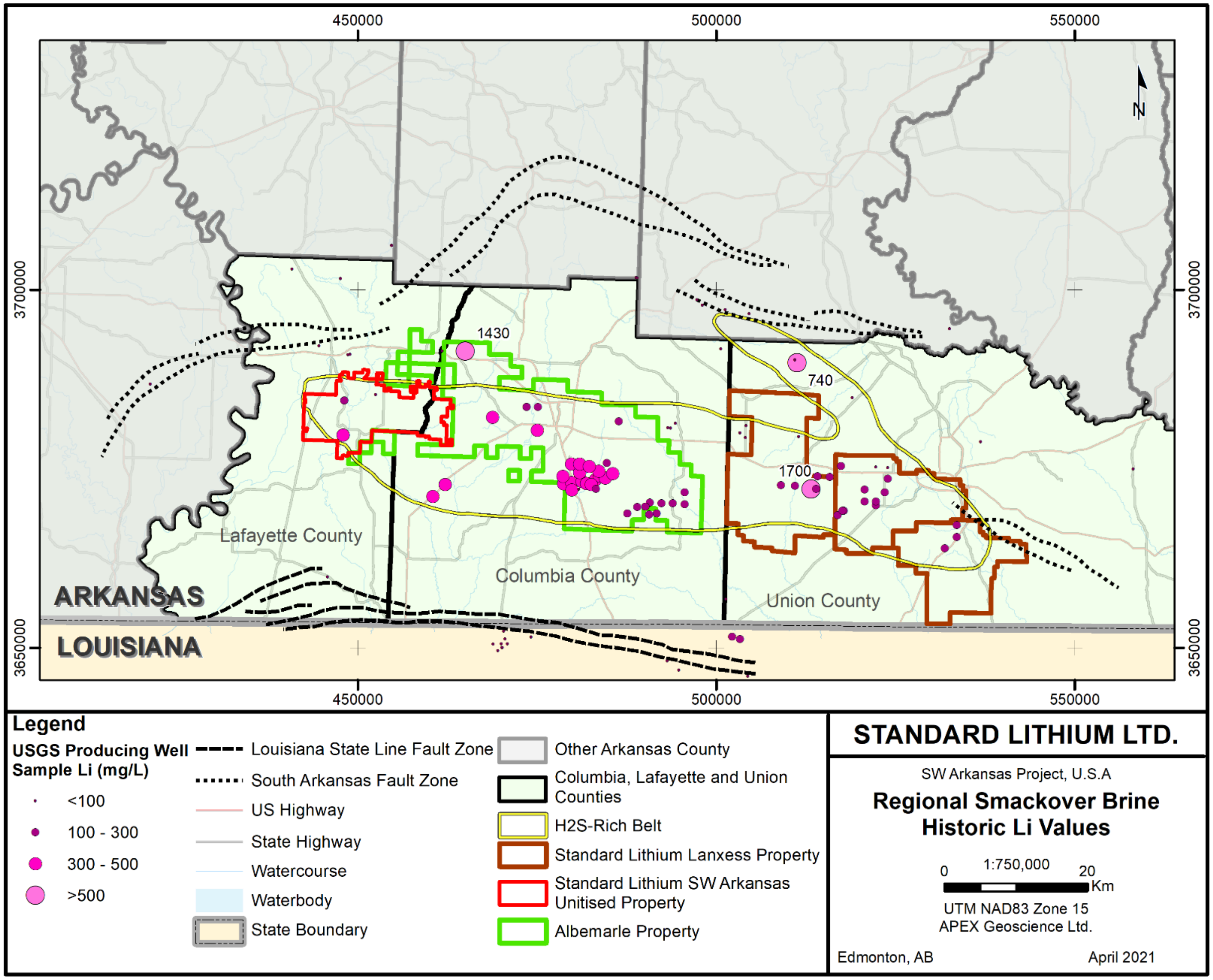
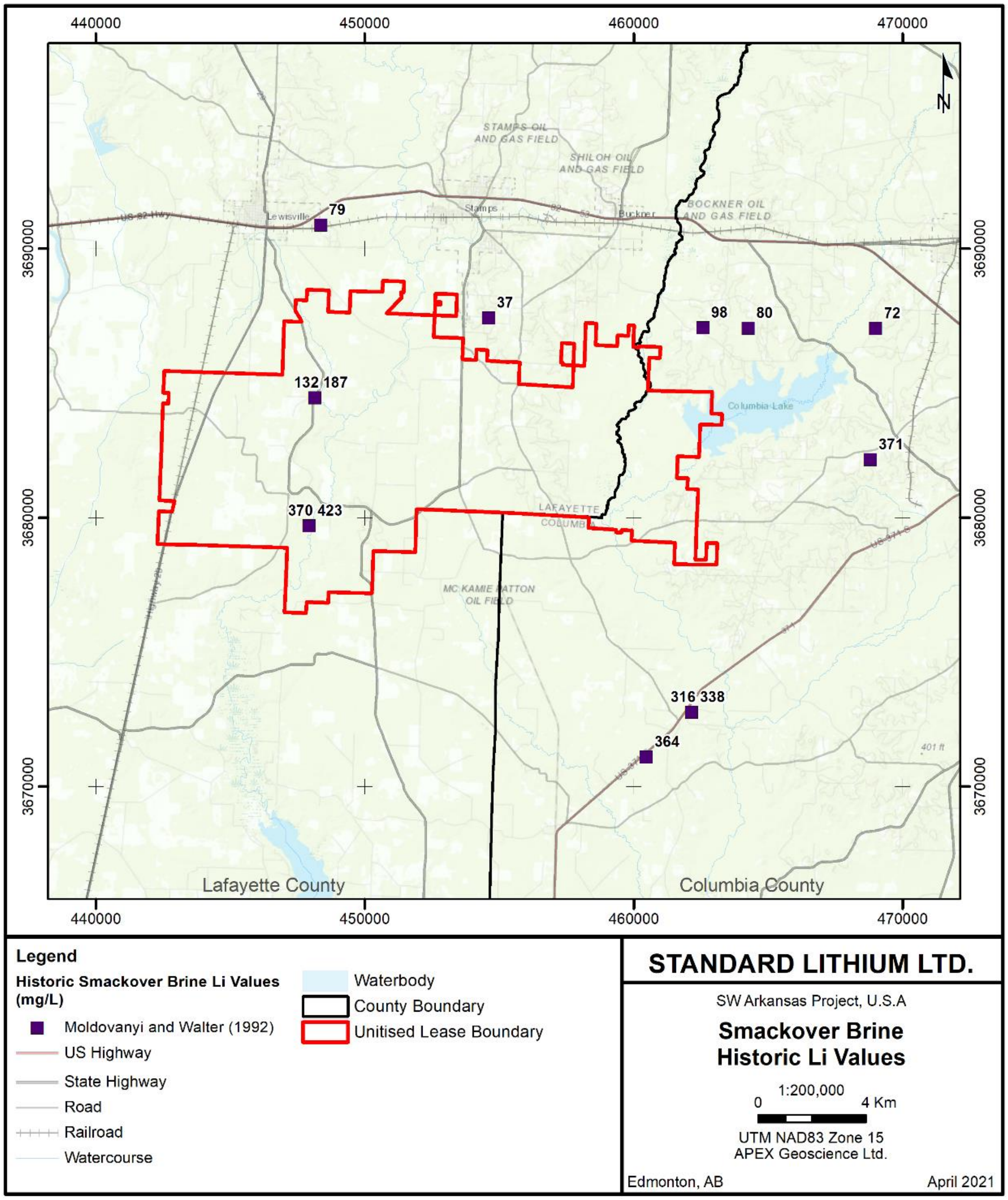


Figure 6-3. Smackover Formation lithium brine values derived within and surrounding the SWA Property. Source: from the USGS National Produced Waters Geochemical Database, Blondes et al. (2016).



These data provide independent historical documentation that the Smackover Formation brines contain lithium on the Property as well as the surrounding area. This brine information on the Property will be used to provide data for resource estimation. Additional Smackover Formation brine samples that have been collected from the Property by Standard Lithium are discussed further in Section 9.2 and Section 14.8.

6.3 SWA Property Historical Infrastructure Summary

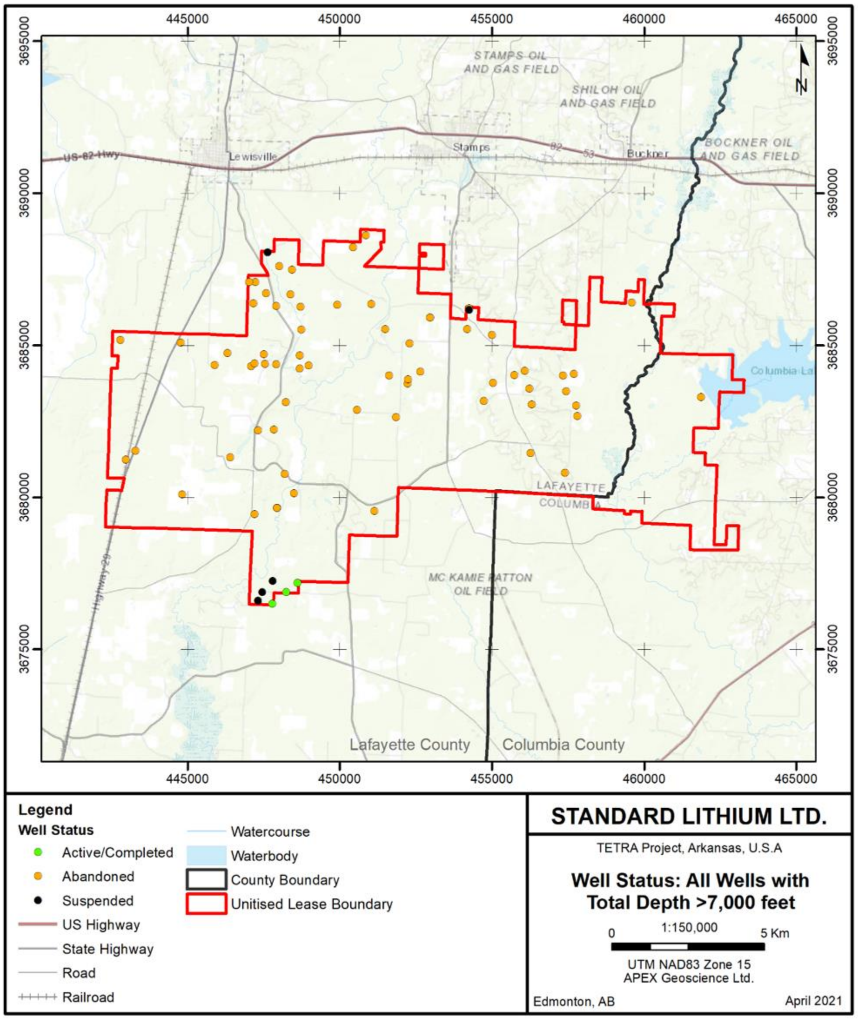
Several Smackover Formation oilfields were located on the SWA Property and included: Lewisville, McKamie-Patton, McKamie NE, Mars Hill, Mt. Vernon, and Kress City (AOGC, 2016). Currently only the McKamie-Patton field is operating, and the other two fields were abandoned. On the SWA Property, 81 oil wells were drilled by oil companies during exploration of the Smackover Formation (Figure 6-4).

All oil wells in the SWA Property, except for those wells located in the McKamie Patton field, have been plugged-and-abandoned or suspended. The McKamie Patton oil field is in the south-central portion of the SWA Property. The status of 33 total Smackover Formation wells within the McKamie-Patton field is as follows:

- 11 of the 33 wells are either plugged (suspended) or abandoned;
- 20 wells were completed; and,
- 2 wells are currently producing (wells MKP-20 and MKP-21).

The hydrocarbon is collected from the wells and a gathering system of pipelines directs the oil and gas to a process facility owned by Mission Creek Resources, LLC (Mission Creek). The McKamie Gas Processing Facility is located south of the SWA Property.

Figure 6-4. Well status on the SWA Property (wells with total depth >7,000 feet).



7 GEOLOGICAL SETTING AND MINERALIZATION

The Gulf Coast region formed as part of the complex breakup of the mega-continent Pangea starting about 180 million years ago (Ma). Development of one of the northern supercontinents, Laurentia, involved geological factors that were crucial for the formation of a carbonate platform that hosts vast reservoirs of lithium bearing brine. To communicate this unique geological environment to the reader, the author provides a regional through to detailed scale geological review.

The regional geological information includes a summary of the depositional framework of the Gulf Coast region and the ensuing Triassic-Jurassic stratigraphic deposition with emphasis on the subject unit, the Smackover Formation. Detailed geological information is at the SWA Project scale and introduces the geological and hydrogeological characteristics of the Upper and Middle Smackover Formations, which defines the resource horizon being evaluated in this Technical Report.

7.1 Gulf Coast Tectono-Depositional Framework

Deposition of the Upper Jurassic Smackover Formation is directly linked to the evolution of the Gulf of Mexico. That is, the central Gulf Coast region experienced Triassic-Jurassic rifting associated with the opening of the Gulf of Mexico and a divergent margin basin characterized by extensional rift tectonics and wrench faulting (Pilger, 1981; Van Siclen, 1984; Salvador, 1987; Winker and Buffler, 1988; Buffler, 1991). The history of the interior salt basins in central and eastern Gulf of Mexico includes a phase of: crustal extension and thinning; a phase of rifting and sea-floor spreading; and a phase of thermal subsidence (Nunn, 1984; Mancini et al., 2008).

A proposed model for the evolution of the Gulf of Mexico and related basin and arch formation in Mississippi, North Louisiana and Arkansas includes:

1. Late Triassic-Early Jurassic rifting that developed pronounced half-grabens bounded by listric normal faults. This phase was accompanied by widespread doming, rifting, and filling of the rift basin(s) with volcanic and non-marine siliciclastic sedimentary (red beds) rocks as North America separated from Africa-South America (Buffler et al., 1981; Salvador, 1991a; Sawyer et al.,1991; Marton and Buffler, 2016).
2. Middle Jurassic rifting, crustal attenuation and the formation of transitional crust, characterized by the evolution of a pattern of alternating basement highs and lows as the Gulf of Mexico area broke up into a series of separate arches/uplifts and subsiding basins. Some of the latter became isolated and filled with thick sequences of evaporites (Sawyer et al., 1991; MacRae and Watkins, 1996; Mancini et al., 2008; Figure 7-1).
3. Late Jurassic sea floor spreading and oceanic crust formation in the deep central Gulf of Mexico characterized by a regional marine transgression related to crustal cooling and subsidence (Sawyer et al.,1991).
4. Subsidence continued into the Early Cretaceous with a ramping up of a Carbonate platform and deposition of shallow to deep water sedimentary rocks along the margins of the basins.
5. Evolution of the Gulf of Mexico region ended with a prominent period of igneous activity and global sea level fall during the Late Cretaceous (mid-Cenomanian) that produced a major lowering of sea level in the region and resulted in the exposure of the shallow Cretaceous platform margin that rimmed the Gulf of Mexico (Salvador, 1991b). This event

is defined by a Gulf-wide unconformity that is most pronounced in the northern Gulf of Mexico area.

Given this scenario, Upper Jurassic evaporite and sedimentary strata that form the integral geological units in this Technical Report, were deposited across much of the Gulf of Mexico coast basin as part of a seaward-dipping wedge of sediment that accumulated in differentially subsiding basins on the passive margin of the North American continent. These units include formations of the Louark Group: 1) the major lithium brine and hydrocarbon reservoir/aquifer known as the Smackover Formation; and 2) the Smackover's overlying and underlying aquitards, the Buckner Anhydrite Member of the Haynesville Formation and the Norphlet Formation salt respectively.

The Smackover Formation in south Arkansas consists of a shoaling-upward cycle capped by ooidal/oncolitic packstone and grainstone (Vestal, 1950), with a maximum thickness of 365 m (1,200 feet). It has been interpreted as a low-gradient slope (<1°) homoclinal ramp succession due to its series of strike-oriented, relatively narrow depositional lithofacies belts across Texas, Arkansas, Louisiana, and Mississippi (Ahr, 1973; Bishop, 1968; Handford and Baria, 2007; Figure 7-2). These belts include evaporite and redbed sequences in the north that change basin-ward into ooidal (inner ramp beaches and shoals) peloidal facies belt (mid-outer ramp), and laminated mudstone (basin).

Figure 7-1. Tectonic framework of the northern part of the Gulf of Mexico region (from Marcini et al., 2008; who modified the work of MacRae and Watkins, 1996). The approximate location of the SWA Property is denoted with a red star.

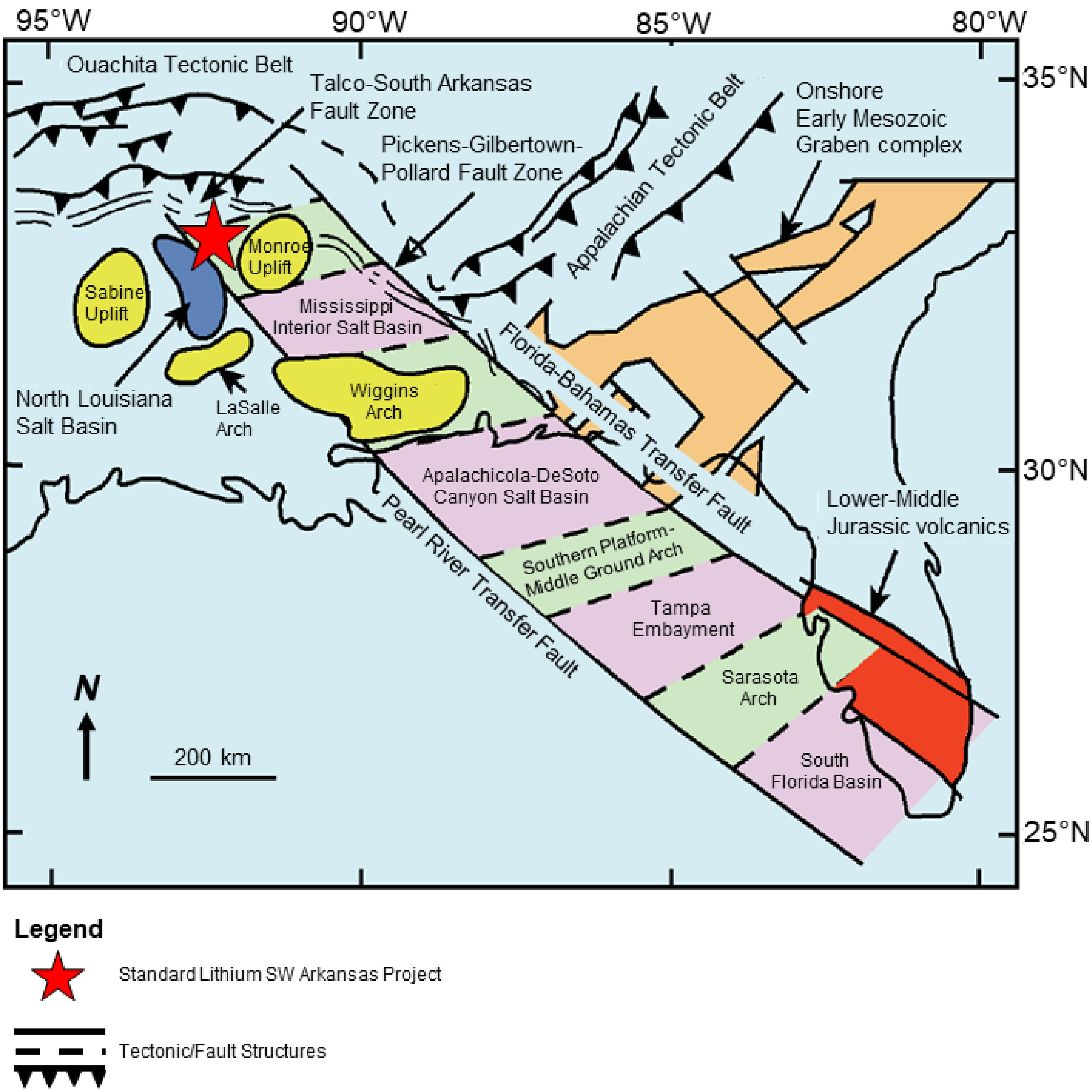
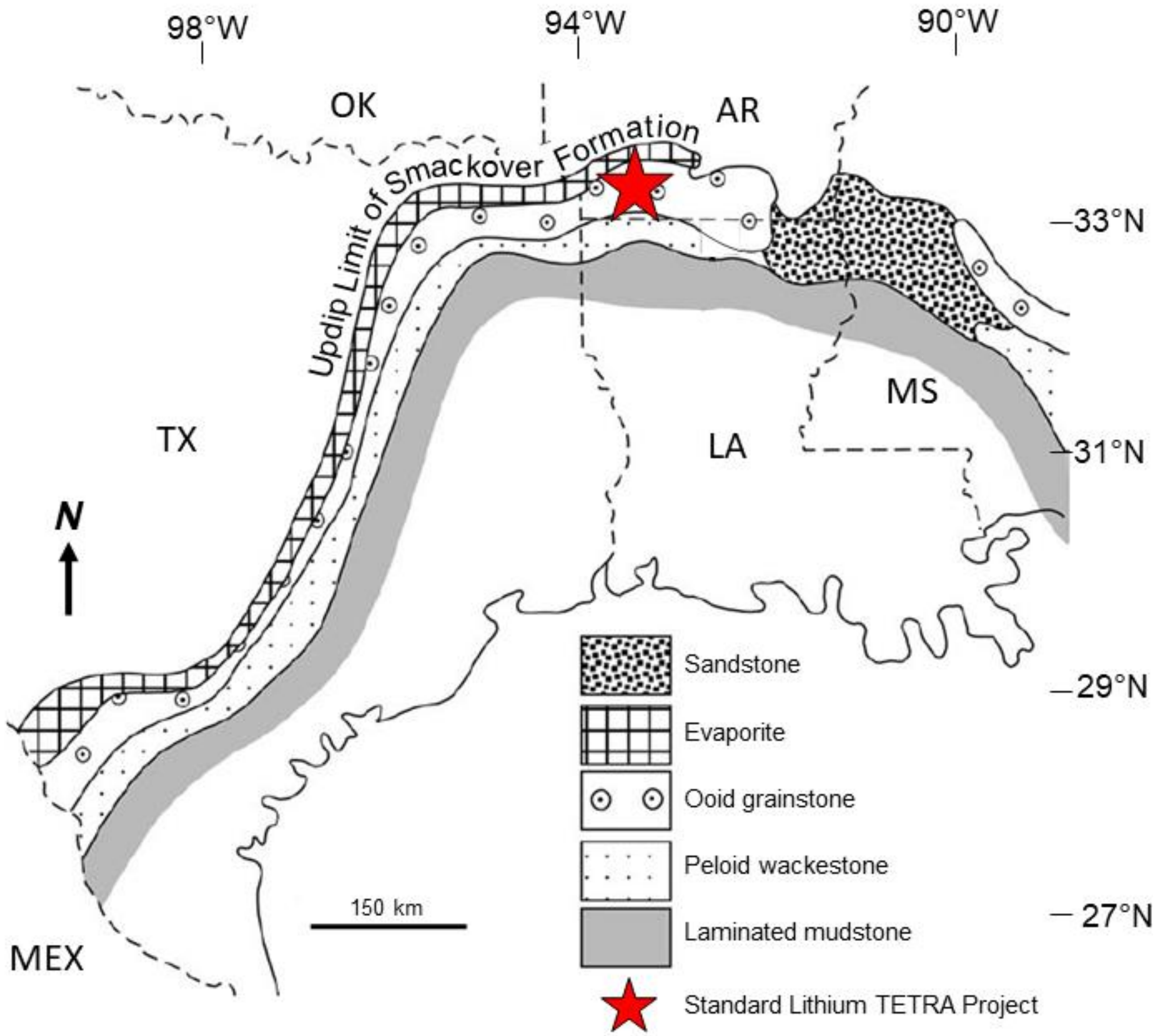


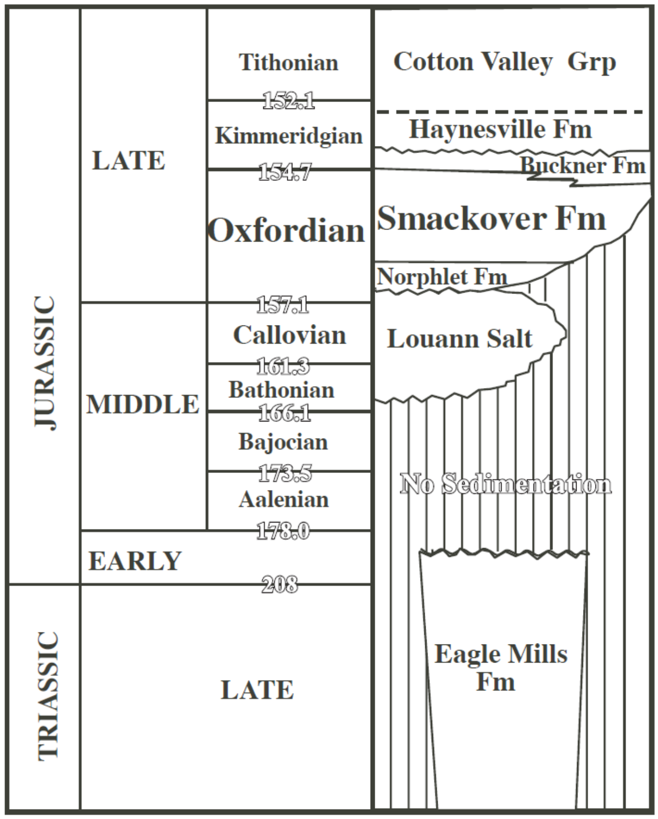
Figure 7-2. Regional map of Smackover Formation lithofacies belts in the U.S. Gulf Coast basin. Source is Handford and Baria (2007), who modified the work of Ahr (1973) and Bishop (1968). The approximate location of the SWA Property is denoted with a red star.



7.2 Triassic-Jurassic Stratigraphy

A stratigraphic table of the Triassic-Jurassic stratigraphy is presented in Table 7-1. The Smackover Formation and its surrounding geological formations are described in the text that follows. During rifting phases, evolving grabens were filled with the earliest Late Triassic-Early Jurassic red-bed sedimentary sequences of the Eagle Mills Formation (Table 7-1). This unit comprises a variety of terrestrial sedimentary rocks including red, reddish-brown, purplish, and greenish-gray coloured shale, mudstone, siltstone, and lesser amounts of sandstone and conglomerate. In southern Arkansas, the Eagle Mills Formation includes conglomeratic sandstone and red shale with igneous fragments (diabase). The Late Triassic-Early Jurassic age is based on the study of remnant plants and radiometric dating of intrusive material (Scott et al., 1961; Baldwin and Adams, 1971).

Table 7-1. Stratigraphic table of the Late Triassic to Late Jurassic formations of the northern United States Gulf Coast (from Heydari and Baria, 2005).



In central-north Louisiana and southern Arkansas, rifting and continental crustal attenuation resulted in a period of non-deposition as evidenced by a 40-million-year hiatus of the depositional record. Late Middle Jurassic (Bathonian–Callovian) depositional units include evaporite, red clastic, and basal conglomerate of the Werner Anhydrite (Hazzard et al., 1947). The Werner-Louann sequence unconformably overlies the Eagle Mills Formation or older 'basement' rocks and forms the basal unit(s) for the overlying Late Jurassic Louark Group, which includes the Norphlet, Smackover and Haynesville-Buckner Formations (Table 7-1). More notably, continued basin-wide restriction resulted in deposition of a thick succession of the Louann Salt during the Callovian (over 3,050 m thick in some places; 10,000 feet; Salvador, 1990; Zimmerman, 1992). The Louann Salt has been estimated to cover as much as 466,000 km^2 (180,000 square miles) in the Gulf of Mexico region (Hazzard et al., 1947).

The South Arkansas fault system and the Louisiana State Line graben are approximately parallel to regional strike of the Smackover Formation deposition and were active during the Jurassic, likely resulting from salt tectonics in the underlying Louann Formation (see Figure 7-1; Bishop, 1973: Troell and Robinson, 1987). The present up-dip limit of the Louann Salt is generally marked by the South Arkansas fault system; a feature believed to have been produced during the Late Jurassic by downdip gravity sliding of the Louann Salt (Troell and Robinson, 1987).

The Upper Jurassic Norphlet Formation unconformably overlies the Louann Salt and older units near the margins of the basin (Hazzard et al., 1947; Bishop, 1967). The Norphlet Formation was deposited during a regional sea-level low stand. The maximum thickness of the Norphlet

Formation is about 45 m (150 feet) and is comprised of alluvial-fan sandstone and conglomerate, channel and interdune redbed and aeolian sandstone (Wade and Moore, 1993; Mancini et al., 2008). Norphlet Formation fluvial deposition in southern Arkansas is characterized by gravel with interbedded red and grey mudstone (Mancini et al., 2008) and is approximately 15 m (50 feet) thick (Zimmerman, 1992; Hunt, 2013).

Marine deposition resumed during the late Oxfordian, as the Late Jurassic seas transgressed, initiating the deposition of the Smackover Formation, which conformably overlies the Norphlet Formation. The Smackover Formation is the focus of this Technical Report and is therefore described in detail in Section 7.3.

Smackover Formation Carbonate rocks are succeeded by mixed evaporite, siliciclastic, and dolomite of the Buckner Formation, and then by a thick Kimmeridgian–Tithonian succession of marine, deltaic, and fluvial siliciclastic rocks of the Haynesville Formation and the Cotton Valley Group (Table 7-1).

The Buckner Formation consists of evaporitic deposits and associated redbeds, reflecting a depositional environment that is less marine, or shallower water marine, than those of the underlying Smackover Formation (Salvador, 1987). The Buckner Formation is made up of intercalated 2 to 6 m thick salt/anhydrite and marine limestone and extends from the Florida Panhandle to South Texas (Mann, 1988). Distinct facies change occurs along the crests of a line of anticlines that extend from the Catesville oilfield in Union County westward to the Dorcheat-Macedonia field in Columbia County. North of this structural trend, the Buckner Formation consists of, from top to bottom, nonmarine red shale, anhydrite, and dolomite (Akin and Graves, 1969). To the south, equivalent beds become sandy. The anhydrite facies indicate the presence of a barrier restricting normal flow of seawater during Buckner Formation deposition.

The Late Jurassic Cotton Valley Group in southern Arkansas and northern Louisiana lies unconformably on the Haynesville Formation of the Louark Group (Table 7-1). In ascending order, Swain and Anderson (1993) divided the Cotton Valley Group into the Millerton (siliciclastic, mainly shale, shelf unit), Shongaloo (foreshelf and shelf edge silty shale and sandstone), and Dorcheat (sandstone and siltstone) Formations. The Millerton Formation, or Bossier marine shale pinches out updip in southernmost Arkansas (Mancini et al., 2008). The Haynesville Formation conformably underlies the Bossier; and where the Haynesville Formation is absent, the Bossier rests on the Smackover Formation limestone. In Arkansas, the Dorcheat Formation contains increasing amounts of sandstone before pinching out (Forgotson, 1954).

7.3 Smackover Formation

The Smackover Formation was named after the Smackover field, Union County, Arkansas, where oil was first produced. Hydrocarbons were discovered in the Late Jurassic Smackover Formation in the mid-1920s. Since then, the Smackover Formation has produced large quantities of oil and gas in a production trend that extends over an area of 100 km (62 miles) by 1,000 km (621 miles) on the margins of the Gulf of Mexico from Texas to Florida (Moore, 1984).

Consequently, the Smackover Formation has been subject to many investigations that address the unit's stratigraphy, lithofacies and depositional environment (e.g., Ahr, 1973; Akin and Graves, 1969; Baria *et al.,* 1982; Bishop, 1968, 1971a, 1973; Budd and Loucks, 1981; Moore and Druckman, 1981; Harris and Dodman, 1982; Moore, 1984; Troell and Robinson, 1987; Chimene, 1991; Hanford and Baria, 2007; Marcini et al., 2008).

Based on ammonite studies from the lower portion of the unit, the Smackover Formation is late Oxfordian in age (Imlay, 1940). The Smackover Formation resulted from Carbonate deposition under shoaling conditions following a relatively rapid transgression over the Norphlet Formation sandstone and Louann Salt. The transgression extended as far northwards in the State of Arkansas to Ouachita County (directly north of Columbia County). The distribution of facies of the ensuing Carbonate deposits was controlled by local paleotopography where high energy facies were deposited in nearshore areas rimming exposed paleohighs and near the up-dip limit of Smackover Formation deposition. Lower-energy strata were deposited in basin centres.

The Late Jurassic Smackover Formation in Arkansas was traditionally divided into two members:

1. An upper ooidal to chalky porous limestone; and
2. A lower member composed of dense argillaceous limestone and dark calcareous shale (Imlay, 1940; Figure 7-3).

Jurassic rocks are not exposed in southern Arkansas, and in southern Arkansas, the Smackover Formation oil and gas reservoir pay zone is situated at depths that range from 2,350 to 3,660 m below ground level (approximately 8,000 to 12,000 feet deep; Moore and Druckman, 1981; Marcini et al., 2008). Accordingly, the two Smackover Formation members were divided based on their wire-line electric logs where the upper member has high self potential and lower resistivity, and the lower member has low self potential and high resistivity.

More recently (e.g., Dickinson, 1968), and in the general context of this Technical Report, the Smackover Formation has been divided into three informal units:

1. The Upper Smackover Formation: An upper, clean, ooidal grainstone that forms the main reservoir rock type of the region due to its high porosity and is also known as the Reynolds Member;
2. The Middle Smackover Formation: A middle unit composed of brown, dense, laminated, pelletal, lime-mudstone and fossiliferous lime-wackestone. Locally the upper portion of this unit is also pelletoid and oolitic (Dickinson, 1968); and,
3. The Brown Dense: A lower Smackover Formation unit comprised of dark-brown, fine-grained, laminated, argillaceous, lime-mud sequence (Dickinson, 1968; Moore and Druckman, 1981; Troell and Robinson, 1986).

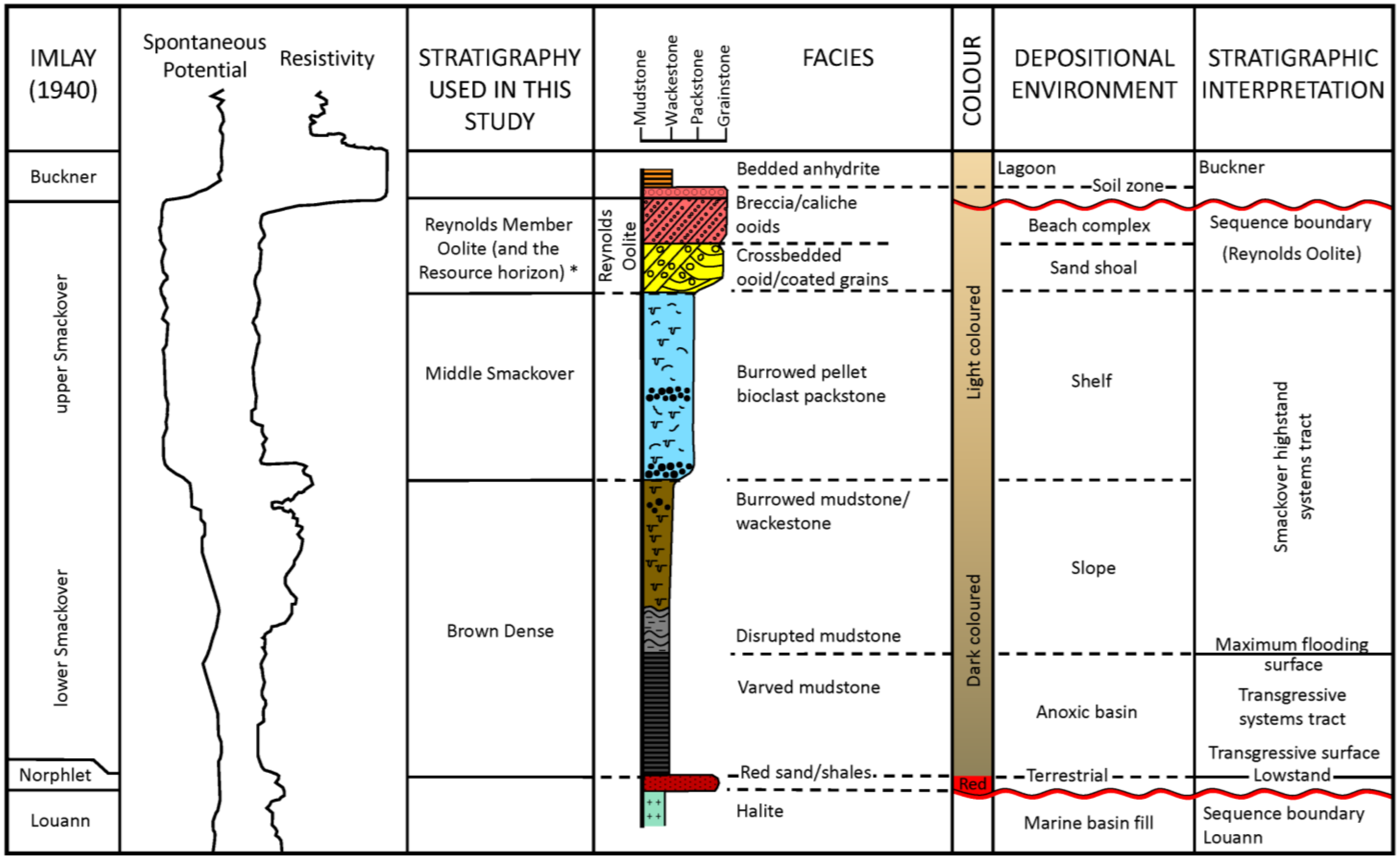
The correlating depositional environment and stratigraphic interpretation of these three Smackover Formation sub-units is shown on Figure 7-3 and from top to bottom as:

1. An ooidal beach complex and/or sand shoal.
2. A shelf high-stand system tract deposited at and near the time of maximum transgression, and during/after a period of rapidly increasing water depth. During middle Smackover-time, prolific production of high-energy carbonate sediment on the flanks of the paleohighs initiated a prograding phase of Smackover Formation deposition.
3. Transgressive systems tract deposits formed in shallow water during relative sea level standstill. The ooidal deposits are generally arranged in a succession of stacked, upward-shallowing cycles that grade from subtidal strata at their bases to shallower subtidal to supratidal strata at their tops (Benson, 1988; Mancini et al., 1990).

From southern Arkansas to northern Louisiana, the Smackover Formation ranges from 0 to 365 m thick (0 to 1,200 feet; Dickinson, 1968). The upper Smackover Formation or Reynolds Member lime-grainstone maintains a thickness of 90 to 120 m (300 to 400 feet) across southern Arkansas (Aiken and Graves, 1969) and reaches a maximum thickness of almost 300 m (1,000 feet) near the Arkansas-Louisiana state line (Moore and Druckman, 1981). The Smackover Formation thickens to the south of a westward-trending series of anticlines that extend from the Catesville oilfield in Union County westward to the Dorcheat-Macedonia field in Columbia County until it interfingers with the Millerton Formation (Bossier shale) to the south.

Smackover Formation hydrocarbon traps include structural and stratigraphic traps, and a combination of the two. Evaporites have played a role in Smackover Formation reservoir development. Evaporites are found in the underlying Louann Salt, the overlying Buckner Formation and within the Smackover Formation itself.

Figure 7-3. Stratigraphic depositional environments of the Smackover Formation. The mineral resource estimated in this Technical Report includes the Upper Smackover Formation (Reynolds Member on this figure) and the Middle Smackover Formation.



Smackover Formation diagenesis was dominated by early cementation, leaching of calcium carbonate allochems and dolomitization; other processes include: pressure solution, late (post-dolomitization) calcite and anhydrite cementation, and fracturing, both tectonic and caused by collapse of partially dissolved rock frameworks (Kopaska-Merkel et al., 1992). Early marine phreatic cementation was followed by leaching of ooids and widespread particle dissolution that vastly increased porosity values (to 40% or more) but had little direct effect on permeability. Early dolomitization of uppermost Smackover Formation strata by reflux of hypersaline brine was widespread and is responsible for formation and/or preservation of many permeable Smackover Formation pore systems.

The Upper Smackover and Middle Smackover formations are the target horizon for the mineral resource evaluation in this Technical Report. Their depositional models have been described as follows:

- The Upper Smackover Formation or Reynolds Member was deposited in a beach and/or shoal environment and composed of ooids and non-sketelal Carbonate that formed ooidal, chalky limestone (Vestal, 1950; Tonietto and Pope, 2013).
- The Middle Smackover Formation was deposited in a high-stand system tract in response to sea level rise. The uppermost portion of the Middle Smackover Formation would have been in the transition zone to a shallower sea water environment forming laminated, pelletal, lime-mudstone and fossiliferous lime-wackestone and locally the upper portion of this unit is also pelletoid and oolitic limestone (Dickinson, 1968).

These carbonate units are widespread, relatively uniform in thickness and have definite patterns of regional and local lithic changes. The most common Smackover Formation reservoir rocks occur with the Upper Smackover Formation, which can comprise a variety of grainstone and grainstone/packstone rock-units that often are dominated by pellet, ooids and oncoids (Akin and Graves, 1969; Moore and Druckman, 1981; Troell and Robinson, 1987).

The occurrence of reservoir-grade rocks (porosity of at least 6% and permeability of a least 0.1 mD) in the Smackover Formation is dependent on 1) deposition of porous and permeable sediments in a variety of setting; and 2) diagenetic processes that have preserved, enhanced, or created porosity and permeability in originally permeable and/or impermeable strata (Kopaska-Merkel et al., 1992).

7.4 Property Geology: Characterization of the Smackover Formation

To assess the SWA Property a well review was completed. A summary of the statistics from the well data review include:

- 2,444 wells have been drilled into the subsurface in the general SWA Property area, 2,041 of which were deep enough (2,135 m, or 7,000 feet) to penetrate the Upper Smackover Formation;
- 104 wells had electric logs available within the SWA Property that included the top of the Upper Smackover Formation;
- 32 wells had electric logs available within the SWA Property that included the base of the Upper Smackover Formation;
- 19 wells had electric logs available within the SWA Property that included the base of the Middle Smackover Formation; and,

- 29 wells had density logs and/or porosity logs, 19 of which logged the entire Upper Smackover Formation.

These subsurface well data were acquired and entered into a variety of geological interpretation software systems including Petra™, Kingdom® and Logscan to evaluate and show regional trends of the Smackover Formation throughout the SWA Property.

Based on analysis of the subsurface well data, key geologic formations are relatively easy to correlate within the SWA Property area. The top portion of the Upper Smackover Formation is comprised of a tight calcarenite-Carbonate mudstone facies. Below the top portion the Upper Smackover Formation is porous oöidal stratigraphy that is usually well-defined on raster logs and/or log ASCII standard files (LAS).

To illustrate this, a 'type log' is presented in Figure 7-4. The electric log from this well depicts the formation markers for the Buckner Formation, top and base of Upper Smackover Formation and Lower Smackover Formations. The Reynolds Member ooidal limestone portion of the Upper Smackover Formation is depicted on the log as having a noticeably lower gamma ray signature and distinct 'gap' in resistivity between the medium and deep induction logs, and the spherically focused log (light blue highlighted zone on Figure 7-4).

To determine the continuity and lateral extent of the Upper Smackover Formation within the SWA Property, electric logs from 49 wells were used to develop five cross-sections, three of which are presented in this Technical Report. The locations of the three cross-sections is presented in Figure 7-5. The cross-sections include:

- Two North-South cross-sections labelled A-A' and B-B' (Figures 7-6 and 7-7); and
- A single East-West cross section, E-E', which transects the entire length of the SWA Property (Figure 7-8).

Figure 7-4. Type Smackover Formation section depicting resource estimation zones that were used in this Technical Report. The ASCII log file is from Trend Resources Limited Neal Ellis #1 (API: 03-731-0765-00-00). The well is in Section 19, Township 16S Range 23W5 and has a total depth of 2,659 m (8,723 feet).

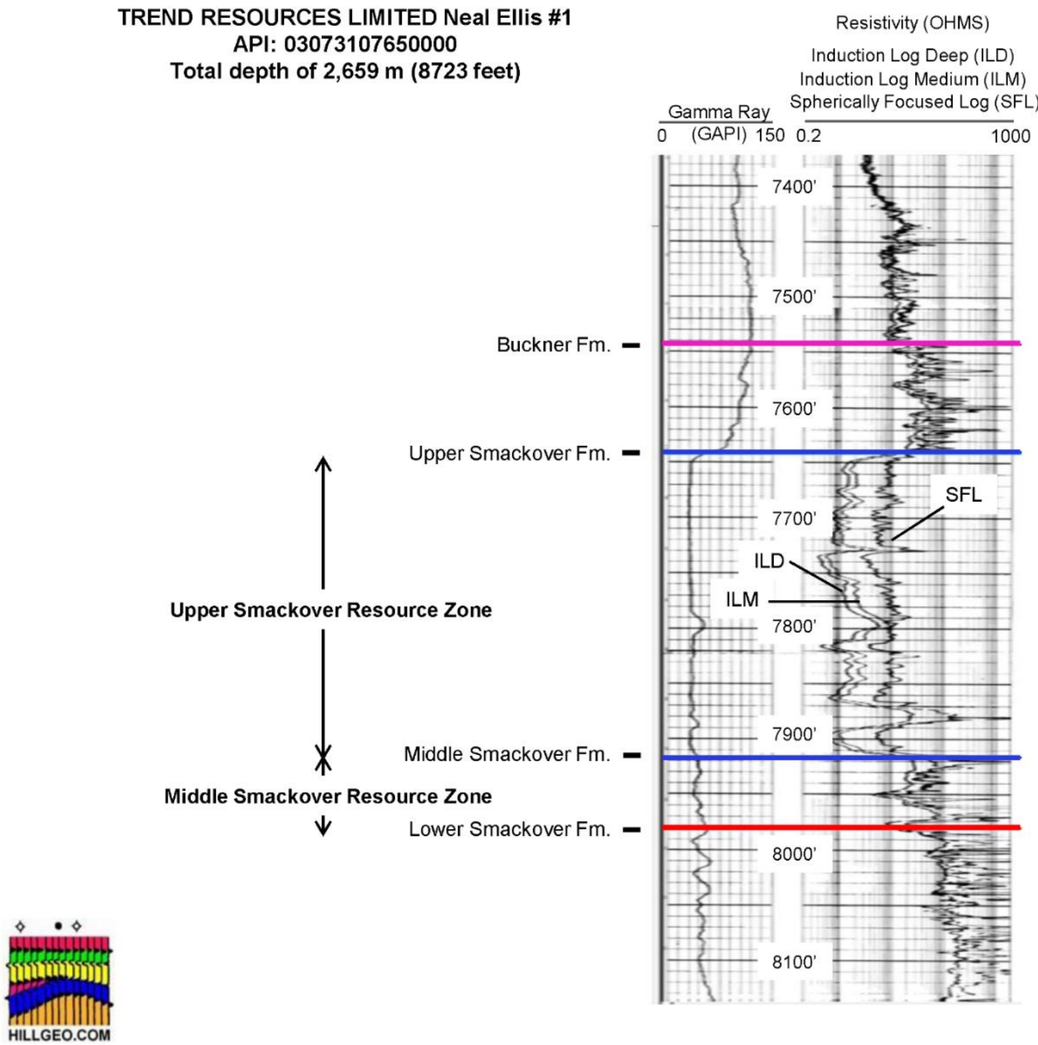


Figure 7-5. Wells selected for study and location of cross-sections.

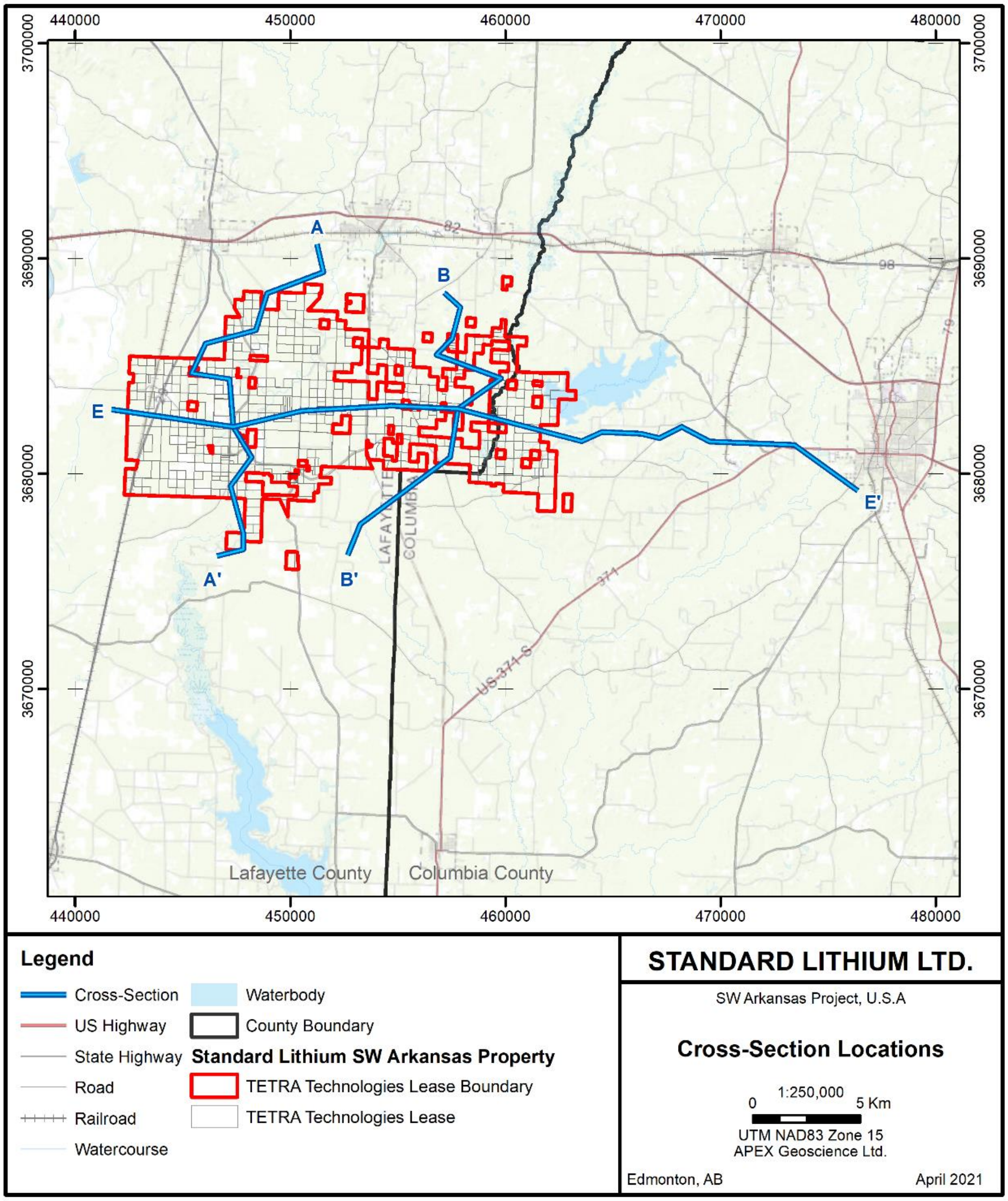


Figure 7-6. North-South cross-section A-A' of the Smackover Formation and associated geological units in the SWA Property area. The section is hung using the Upper Smackover Formation as a datum.

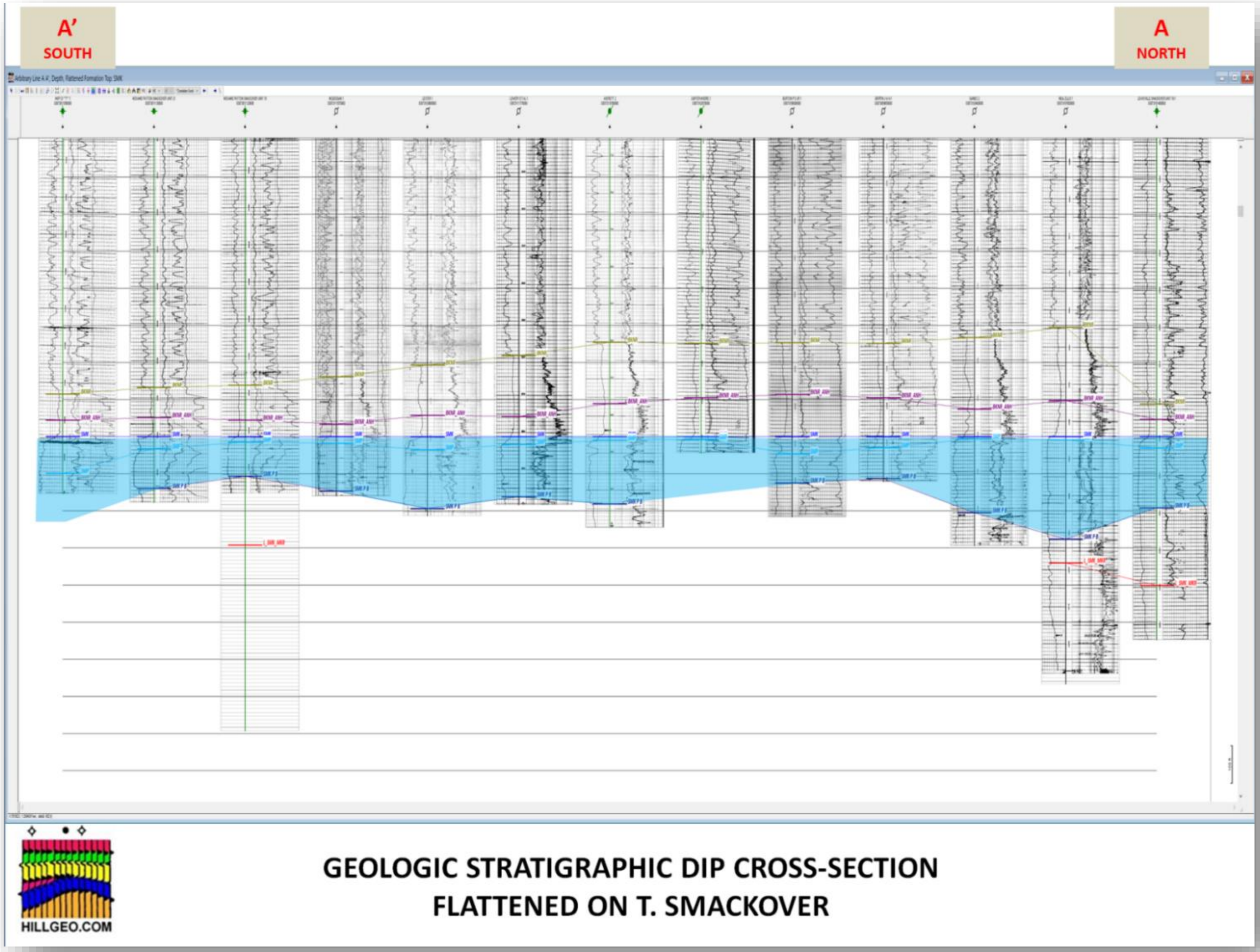


Figure 7-7. North-South cross-section B-B' of the Smackover Formation and associated geological units in the SWA Property area. The section is hung using the Upper Smackover Formation as a datum.

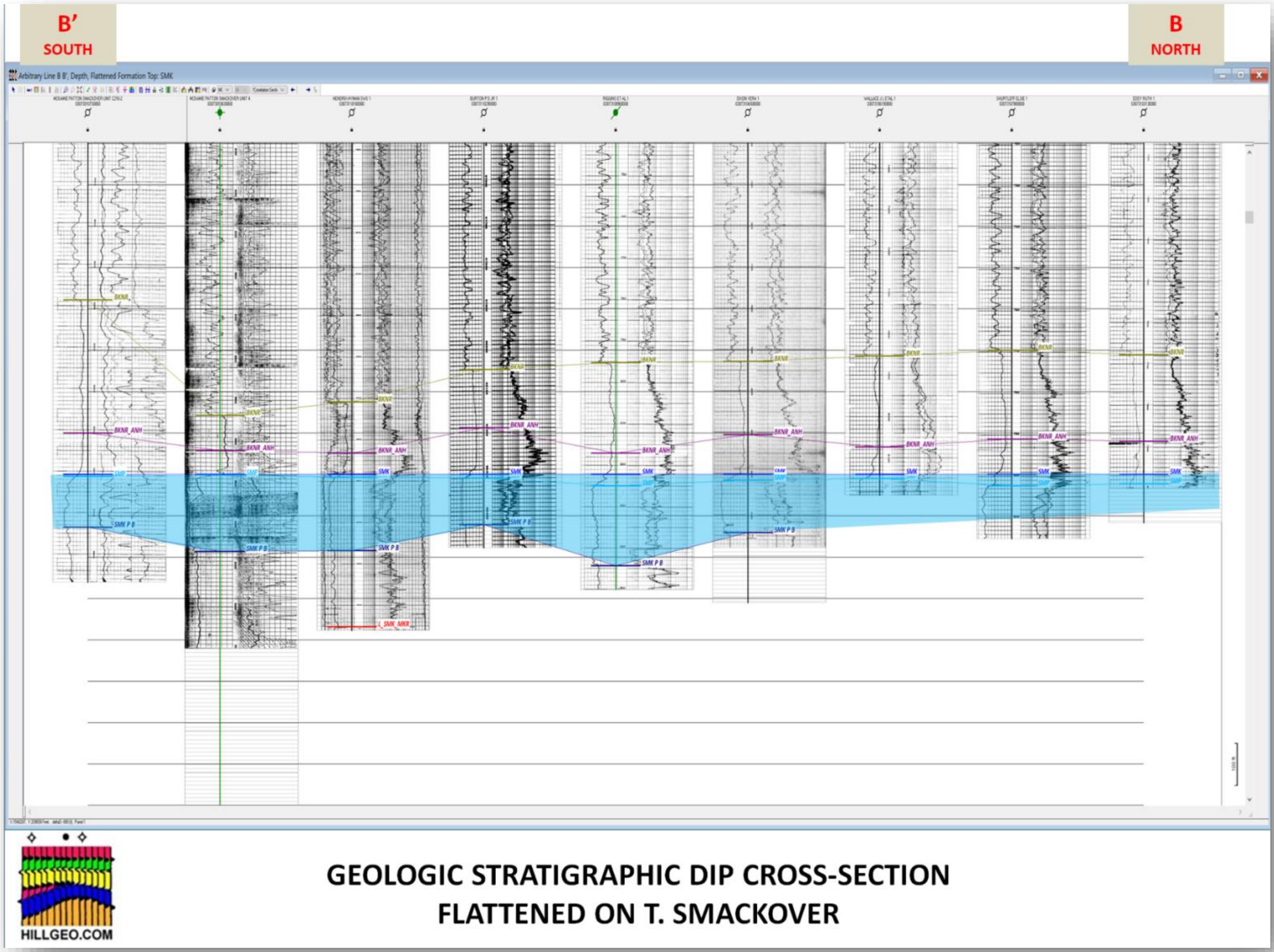
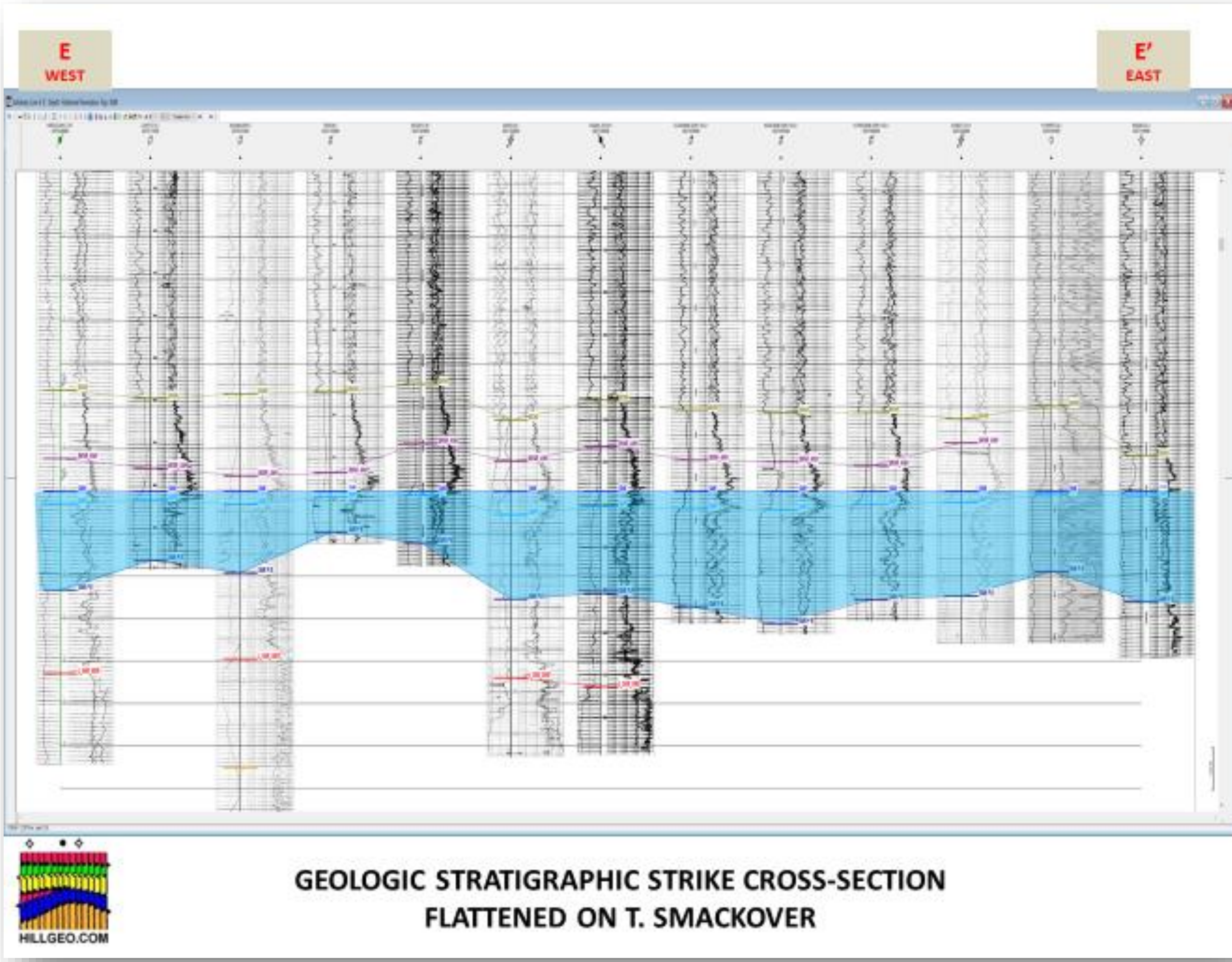


Figure 7-8. East-West cross-section E- E' of the Smackover Formation and associated geological units in the SWA Property area. The section is hung using the Upper Smackover Formation as a datum.



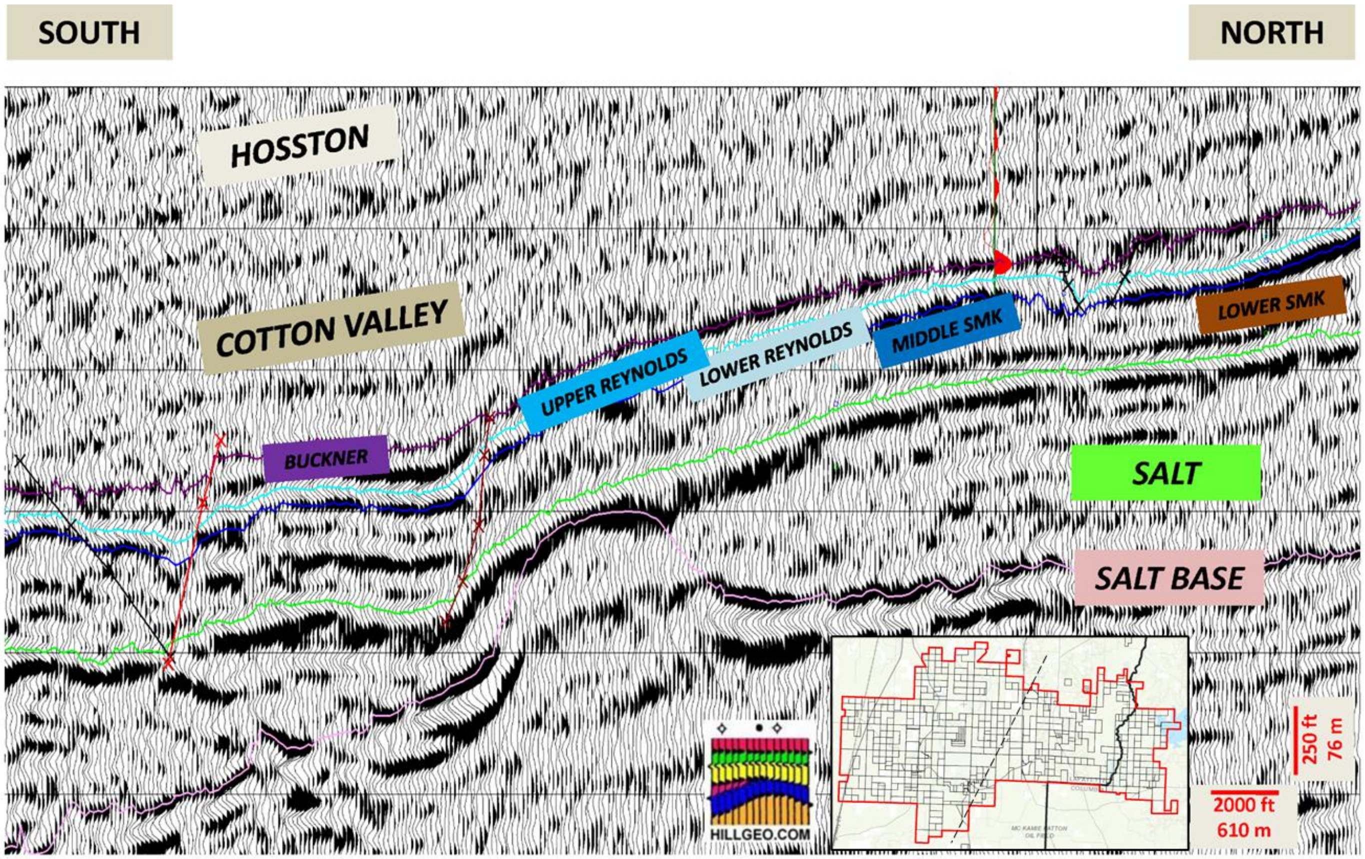
Observations from the sub-surface interpretations that are evident on the cross-sections include:

- The Upper Smackover Formation is laterally continuous and underlies the entire SWA Property.
- The thickest section of Upper Smackover Formation is seen in the north end of cross-section A-A' (Figure 7.6) where a thickness of 81.4 m (267 feet) is observed.
- Cross-sections A-A' and B-B' show the Upper Smackover Formation present in all wells with a thickness varying from about 30.5 m to 76.2 m (100 to 250 feet).
- The average thickness of the Upper Smackover Formation within the SWA Property is approximately 47 m (154 feet).
- An east west trending fault appears to be present in the southern portion of the SWA Property. The Upper Smackover Formation is present on the north and south sides of the fault as discussed in Section 9.

In addition to the Upper Smackover Formation, a second resource horizon occurs directly below the Upper Smackover Formation and is identified as the Middle Smackover Formation. An analysis of the nine electric logs from wells completed below the Upper Smackover Formation indicate an average resource horizon thickness of 12.2 m (40 feet). The nine electric logs are located throughout the SWA Property within the Middle Smackover Formation and have similar electric response signatures to the Upper Smackover Formation.

In addition to the electric logs, 206 line-km (128 line-miles) of proprietary 2D seismic data were used to create integrated seismic subsurface maps. Synthetic seismograms were generated in wells with sonic logs to make a tie between the seismic and well data. An excellent tie was established for the top of the Upper Smackover Formation throughout the SWA Property. A 'type example' of the seismic data is presented in Figure 7-9; the Upper Smackover Formation or Reynolds Member appears as a strong trough on the seismic data directly below the distinct Buckner Formation marker. The seismic section is located between the cross-section A-A' and B-B'. To conclude, the subsurface well data and 2-D surface seismic review supports the authors' stratigraphic depiction of the Upper and Middle Smackover Formations within the SWA Property. These stratigraphic horizons have been selected for mineral resource modelling and estimation in this Technical Report. Additional subsurface detail including stratigraphic surface structural contours is presented in Section 9.1.1, Exploration. The stratigraphic surface grids define the Upper and Middle Smackover Formations domain used in the resource modelling and estimation process (see Section 14).

Figure 7-9. An example of proprietary 2D seismic data showing the uniform and continuous Smackover Formation geologic horizons.



7.5 Structural Geology

Fault zones are developed along the northern periphery of thick salt basins in the eastern Gulf (Mancini et al., 1999). The State Line Fault complex occurs directly south of the SWA Property and formed near the updip limit of a thick salt basin in northern Louisiana (North Louisiana Salt Basin) and is underlain by the thick Jurassic Louann salt that extends midway up the South Arkansas shelf before pinching out (Kalbacher and Sartin, 1986). The State Line Fault complex is associated with salt tectonics during the Smackover-Buckner formations and younger strata deposition (Troell and Robinson, 1987) and the producing Smackover Formation reservoir rocks dip to the southwest across southern Arkansas, likely in relation to the State Line Fault complex (Troell and Robinson, 1987).

During the subsurface investigation conducted as part of this report, the author discovered another east-west fault zone that occurs in the south-central part of the SWA Property. The reader is referred to Section 9.1.2, Delineation of an Inferred Fault Zone Within the SWA Property.

7.6 Upper and Middle Smackover Formation Aquifer

The aquifer associated with the Upper and Middle Smackover formations is defined by a distinct stratigraphic horizon that consists of clean, porous, ooidal grainstone with lime-mudstone and fossiliferous lime-wackestone. Locally, the upper portion of the Middle Smackover Formation is also pelletoid and oolitic limestone. The Upper Smackover Formation or Reynolds Member forms the main oil, gas, and brine reservoir rock of the region due to its high porosity and permeability. The Upper and Middle Smackover formations also correlates with the mineral resource estimate horizon that is the focus of this Technical Report.

The resource horizon occurs underneath the entire Property at depths of approximately -2,230 to -2,905 m (-7,317 to -9,531 feet) beneath the Earth's surface. The target Reynolds Member aquifer has an average thickness of 59 m (193.5 feet; see Section 14.4.2, Geometry and Volume of the Upper and Middle Smackover formation Domains).

Importantly, the aquifer within the Upper and Middle Smackover formations is defined as a 'confined aquifer'. That is, the aquifer is sandwiched between two aquitards that include the overlying Buckner Formation anhydrite and shale and underlying low permeability Lower Smackover (Brown Dense) and Louann Salt. The Buckner Formation has been an effective seal or cap as oil and gas fields are present in the Reynolds Member in Arkansas and on the Property.

In this report, the authors have compiled an extensive dataset, that for example, includes:

1) Historical porosity analyses (n=1,935 core plug samples);
2) Historical permeability analyses (from 6 sources);
3) Property and surrounding area specific permeability and porosity analyses (n=1,643 core plug samples); and,
4) 5,143 total porosity values based on LAS density/porosity logs from wells within the SWA Property and surrounding area.

These data, together with resource thickness determinations, were used to make inferences on the hydrogeological characteristics of the Upper and Middle Smackover formations aquifer within the SWA Property. As per the Canadian Institute of Mining (CIM) Best Practice Guidelines for

Resource and Reserve Estimation for Lithium Brines (1 November 2012), the hydrogeological characterization of the Smackover Formation, is defined and discussed in Section 14.4, Hydrogeological Characterization of the Upper and Middle Smackover Formations. Sub-sections presented within this section discuss porosity, permeability, dispersivity, anisotropy, groundwater levels, and hydraulic conductivity and analysis as they pertain to the updated SWA Property inferred lithium-brine resource estimate presented in this Technical Report.

7.7 Mineralization

The SWA Property is being assessed by Standard Lithium for its lithium-brine potential. The brine is situated within an aquifer associated with the Late Jurassic Smackover Formation, which has produced hydrocarbons since the 1940s on the Property and brine to the east of the Property since the late 1950s.

Hyper-saline brine (total dissolved solids of 293,000 to 448,000 mg/L) with elevated lithium has been verified in the 2018 brine sampling programs conducted by Standard Lithium. The 2018 brine sampling programs and their lithium content are discussed in Section 9.2, 2018 Brine Sampling Program.

8 DEPOSIT TYPES

Lithium is a silver-grey alkali metal that commonly occurs with other alkali metals (sodium, potassium, rubidium, cesium). Lithium's atomic number is three and has an atomic weight of 6.94 making it the lightest metal and the least dense of all elements that are not gases at 20º C (the density in solid form at 20º C is 534 kg/m^3). Lithium has excellent electrical conductivity (i.e., a low electrical resistivity of 9.5 mΩ·cm), making it an ideal component for battery manufacturing where lithium ions move from the negative electrode to the positive electrode during discharge and back when charging. Lithium imparts high mechanical strength and thermal shock resistance in ceramics and glass.

The average crustal abundance of lithium is approximate 17-20 parts per million (ppm) with higher abundances in igneous (28-30 ppm) and sedimentary rocks (53-60 ppm; Evans, 2014; Kunasz, 2006). It should be noted that 1 mg/L lithium is equal to 1 ppm and 0.0001%. Lithium does not occur in elemental form in nature because of its reactivity. There are over 100 minerals that contain lithium, but only a few of these are currently economic to extract. Lithium can be described, priced and quoted as lithium content, Lithium oxide (Li_2O; 0.464 lithium content; conversion is Lithium x 2.153), lithium carbonate (Li_2CO_3; 0.188 lithium content) and lithium carbonate equivalent (LCE"; conversion is lithium x 5.323). Resource estimates and production quantities of lithium are often expressed as LCE.

Lithium is extracted from two main categories of deposits: mineral and brine. With respect to mineral deposits, lithium is extracted only from pegmatite deposits. Pegmatite lithium deposits are found globally and account for half of the lithium produced today (Benson et al., 2017). Spodumene is the most abundant lithium-bearing mineral found in economic deposits.

Brine deposits include unconfined (continental) and confined (i.e., geothermal and subsurface aquifer) brine deposits. Continental brine occurs in endorheic basins where inflowing surface and groundwater is moderately enriched in lithium. All producing lithium brine operations are unconfined (or partially confined), continental deposits; this type of deposit shares several first-order characteristics: (1) arid climate; (2) closed basin containing a playa or salar; (3) tectonically driven subsidence; (4) associated igneous or geothermal activity; (5) suitable lithium source-rocks; (6) one or more adequate aquifers; and (7) sufficient time to concentrate a brine (Bradley et al., 2006).

Economic continental brine aquifers typically occur in areas where high solar evaporation results in beneficiating the brine to higher concentrations of lithium. Geothermal and/or volcanic associations are the favoured mechanisms for introducing lithium into continental basins because lithium-rich brines often exist in areas of volcanic activity (e.g., Imperial Valley, California; Reykjanes field, Iceland; Taupo Volcanic Zone, New Zealand). Typical lithium concentrations in commercially developed continental brine deposits are 200 to 1,500 mg/L.

Selected continental brine deposit examples include: Salar de Uyuni in Bolivia (Bradley et al., 2017); Salar de Atacama in Chile (Garrett, 2004); Salar de Hombre Muerto in Argentina (Meridian, 2008); Salar del Rincon and the Salar del Olaroz in Argentina (Pavlovic and Fowler, 2004; Meridian, 2008; Houston and Gunn, 2011); and the Zhabuye Salt Lake in the Tibetan Plateau, the DXC Salt Lake, and the Qaidam Basin in China (Shengsong, 1986; Zheng et al., 2007). The only active lithium mine in North America is in Silver Peak, Nevada. Lithium brine extraction started in 1966. The lithium occurs in an infilled playa sequence that covers an area of 72 km^2 within a closed drainage basin of 1,342 km^2 (Munk et al., 2011). Average lithium content at the initiation of production was 360 ppm in 1966 declining to 230 ppm in 2008 (Garrett, 2004; Meridian, 2008). The mine currently produces 3,500 tonnes of lithium per year, with the theoretical capacity to produce 6,000 tonnes.

Deep aquifer lithium-brine is frequently pumped as a waste product of hydrocarbon production from confined aquifers at depths of up to 4,000 m. Lithium enrichment of deep saline brines is known to occur worldwide in sedimentary basins of various age, including: the Cambrian Siberian Platform, Russia (Shouakar-Stash et al., 2007); Devonian Michigan Basin (Wilson and Long, 1993); Mississippian–Pennsylvanian reservoirs of the Illinois Basin (Stueber et al., 1993); Pennsylvanian Paradox Basin, Utah (Garrett, 2004); Triassic strata of the Paris Basin, France (Fontes and Matray, 1993); and Jurassic Smackover Formation strata from the Gulf Coast, Arkansas and Texas (Moldovanyi and Walter, 1992).

If the aquifer contains elevated concentrations of lithium or other minerals associated with a mature (or dwindling or dormant) oil and gas field, it can be converted to brine production. A good example is the current bromine production from the LANXESS Smackover Formation in southern Arkansas located 40 km to the east of the SWA Property. At the LANXESS Property, hydrocarbon production ceased in favour of bromine production in 1957. Bromine production from The LANXESS Property has continued for over 50 years. Thus, these deep, confined aquifer resources present an enormous opportunity for extracting minerals such as lithium from the brine.

The source of lithium in hypersaline brine aquifers, including the Smackover Formation, remains subject to debate. Theories specific to the Smackover Formation include, but are not limited to:

- Smackover Li-brine could be a result of the continental drainage of lithium-enriched solutions into the sea where the lithium stems from Triassic age volcanic rocks in the Gulf coast (Collins, 1976). Continental water from springs or other hydrothermal fluids along fault systems could have leached lithium from Triassic aged volcanic rocks. These lithium-enriched fluids then drained into the Smackover Sea and the water was then concentrated by evaporation.
- In the Smackover Formation brine, radiogenic Sr^{87}/Sr^{86} are significantly higher than Late Jurassic seawater suggesting significant strontium contribution from detrital sources such as the Bossier Formation, which overlies and/or interfingers with the Upper Smackover Formation, or were acquired during brine migration (Stueber et al., 1984).
- Lithium was mobilized from the Alleghenian-sourced volcaniclastics (including plutonic rocks) and then concentrated in the underlying Norphlet Formation. These fluids could have originated in the Louann salt and migrated upward through faults or from shallower circulation through the alluvial and wadi facies of the Norphlet Formation (from Chuchla, unpublished, via Daitch, 2018).
- The association between boron, lithium, potassium, and rubidium, coupled with a general lack of clastic sediments in the upper Smackover Formation in southwest Arkansas, suggest that the Smackover Formation brines are mixing with deeper-seated waters that may have been geochemically modified by siliciclastic diagenesis at higher temperature (Walter et al., 1990).
- Regional trends between hydrogen sulphide (H_2S) and boron, lithium, potassium, and rubidium support the association of a higher temperature, deeper-seated fluid end member; these fluids may have migrated into Smackover Formation reservoirs via major

fault systems, the South Arkansas fault system and the Louisiana State Line graben, and their associated fractures (Moldovanyi and Walter, 1992).

With respect to resource modelling of confined aquifer lithium-brine deposits, important criteria include defining the boundaries of the subsurface aquifer; brine chemistry; and understanding of the hydrology of the brine. The reader is referred to the CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brine (1 November 2012). While the guidelines define issues specific to unconfined continental brine deposits (i.e., salars), they do provide general direction for reporting on confined aquifer deposits.

9 EXPLORATION

During 2018, Standard Lithium conducted: 1) a 2018 review of subsurface data as supplied by third-party well and 2-D surface seismic information suppliers; 2) analysis of porosity and permeability from available core; and 3) 2018 geochemical brine sampling program. These programs are discussed in the text that follows.

9.1 Subsurface Data Review

9.1.1 Stratigraphic Surface Interpretation and Definition of the Smackover Formation

During the preparation of this report, Hill Geophysical Consulting (in collaboration with the author) reviewed subsurface well log information from a variety of sources: 1) Depth registered logs from IHS Markit (a software program that allows users to access raster and digital logs); 2) the Arkansas Oil and Gas Board; and 3) the ARK-LA-TEX Log Library Inc. a summary of the statistics from the well data review and description, interpretation of these data is provided in Section 7.4, Property Geology: Characterization of the Smackover Formation.

These data were used to define the Upper Smackover Formation type section and to formulate the upper and lower stratigraphic surfaces of the Upper Smackover Formation and Middle Smackover Formation domain for the resource model used in this Technical Report. This information is presented in Sections 14.1, 14.2 and 14.3 of the Resource Section, and summarized here as the work was part of Standard Lithium's 2018 exploration workplan at the SWA Property.

Structure maps of the top and bottom of the Upper Smackover Formation were constructed using the information from the logs together with the seismic data (Figures 9-1 and 9-2). Industry standard methods for interpreting the data included loading well locations, raster, and digital logs into a Petra™ workstation and picking the key geologic formation tops. The well data were then imported into a Kingdom® seismic workstation where well data was tied to the 2D seismic data. Seismic reflectors, where they existed, were interpreted for the same geologic picks. The time-depth relationship was established using Kingdom's depth conversion. Review of the time-depth conversion showed no issues, and the resulting structure maps fit all well data. The interval isopach of the Upper Smackover Formation shows that the interval is too thin to resolve on the seismic data. Therefore, an isopach map of the well information was created.

Figure 9-1. Structure map of the top of the Upper Smackover Formation.

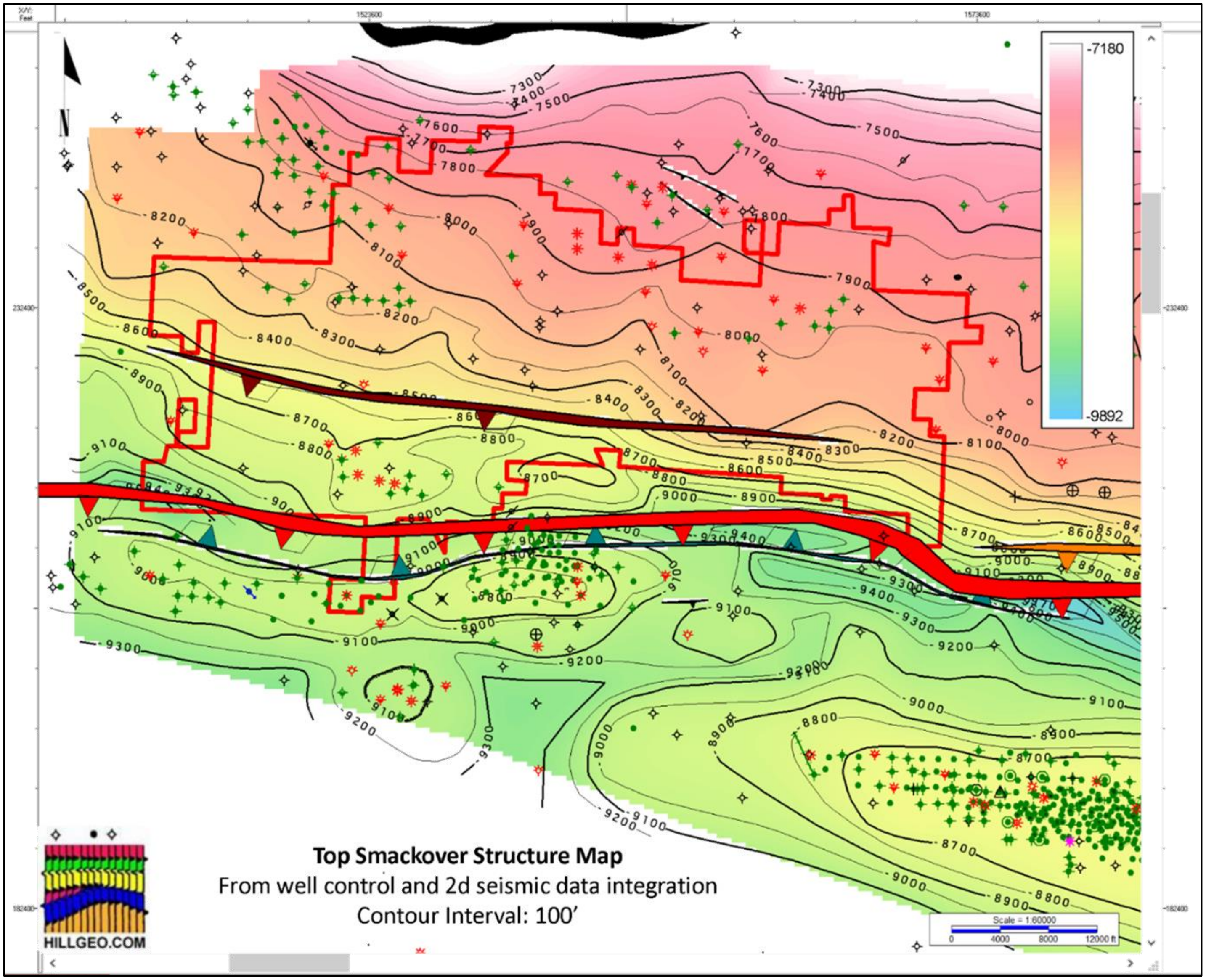
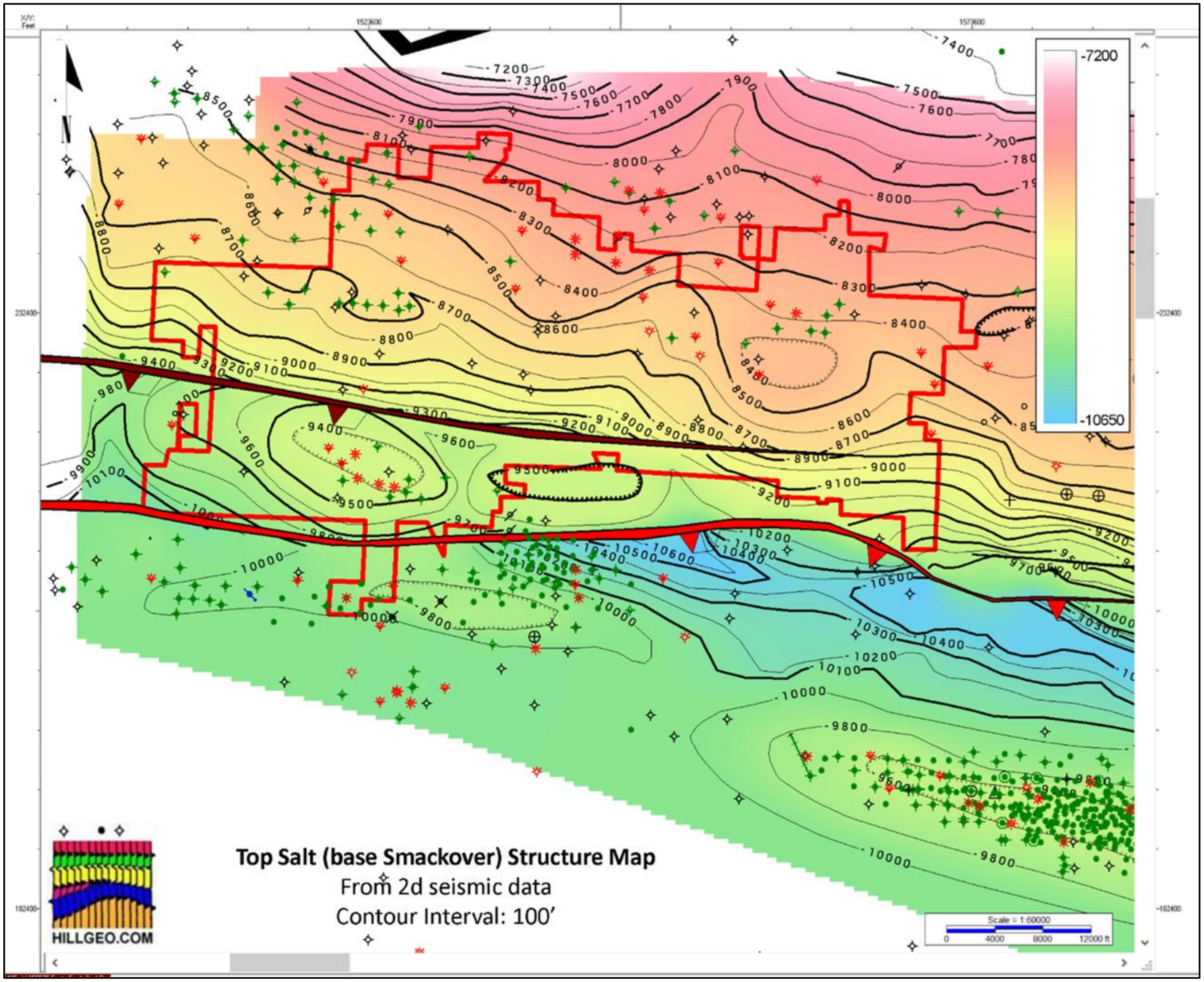


Figure 9-2. Structure map of the bottom of the Upper Smackover Formation.



Depth structure maps to the top, and bottom, of the Upper Smackover Formation are presented in Figures 9-1- and 9-2. On the figures, the red outline represents the Project limits within the regional study area, which was extended beyond the boundaries of the SWA Project to observe regional trends. The depth structure maps show that the general dip of the Upper Smackover Formation is to the southwest and strike is generally northwest-southeast (Figures 9-1 and 9.2). The shallowest top of the Upper Smackover in the area is -2,230 m (-7,317 feet), and the deepest is -2,893 m (-9,491 feet). The structure maps show that the Upper Smackover Formation upper and lower surfaces are uniform and generally correlate with one another. The stratigraphic uniformity between the top and base is what one would expect in a shelf environment of this nature.

9.1.2 Delineation of an Inferred Fault Zone Within the SWA Project

A review of the top of the Buckner Formation and top and bottom of the Smackover Formation structure maps were critical in the definition of a new inferred fault zone that trends east-west in the south-central part of the SWA Project (Figures 9.1, 9.2 and 9.3).

The authors propose that the inferred fault zone represents an important regional stratigraphic deposition transition zone in the region although it is important to point out that the Upper and Middle Smackover Formations are evenly distributed across the fault zone and hence the Smackover Formation aquifers are interconnected across the zone (see Figure 14.4 in Section 14.4.2, Three-Dimensional Modelling and Volume Calculation). The authors propose, however, that the inferred fault zone is presently the most plausible explanation for the variation of lithium concentrations between the southern and northern parts of the SWA Project (see Section 14.1).

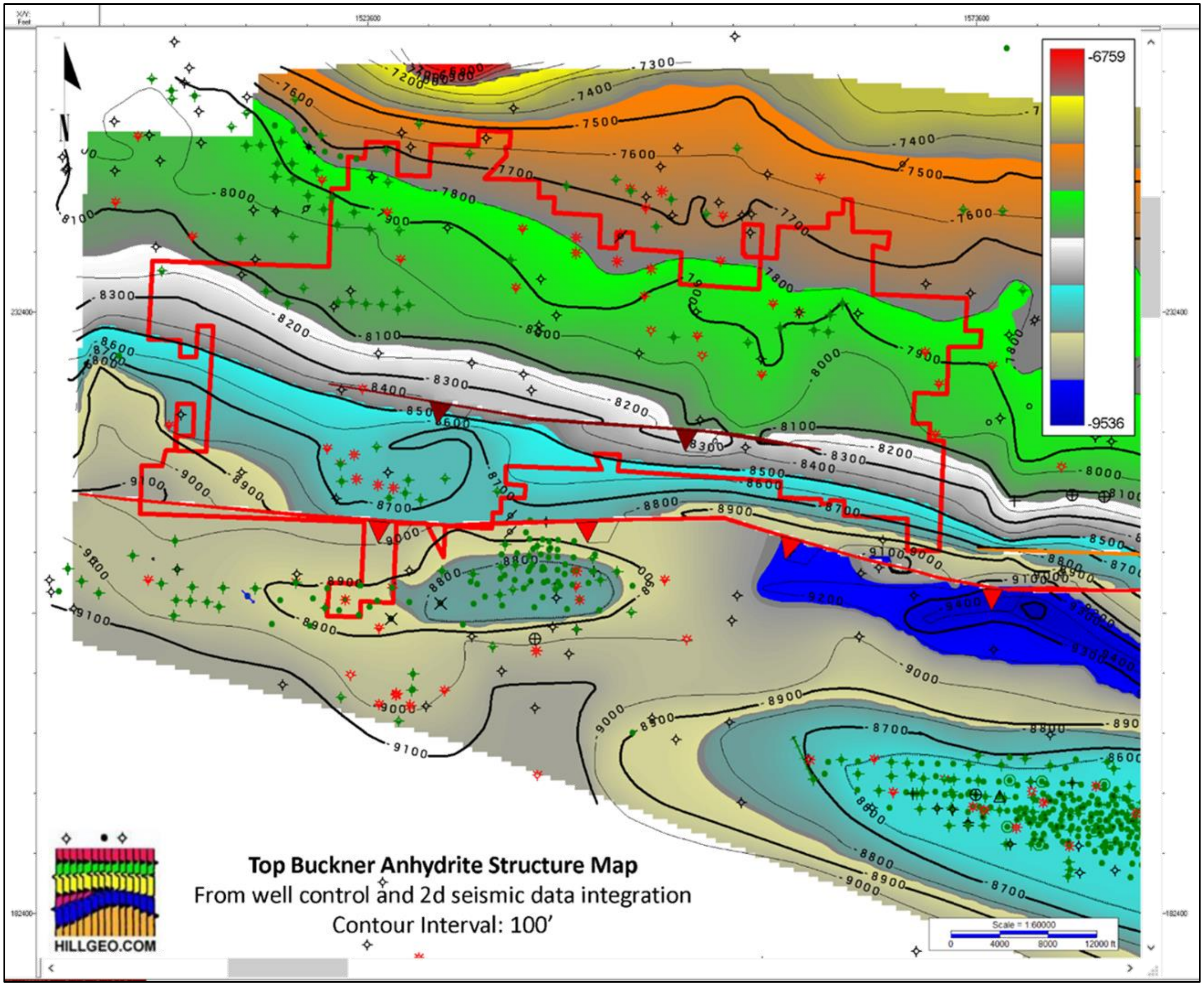
9.1.3 Core Report Analysis and Review

During the preparation of this Technical Report, APEX reviewed the laboratory certificate core reports for 10 wells from the SWA Project and an additional 22 in the Project area (See Section 14.5). Standard Lithium also analysed cores from five wells stored at the Arkansas Geological Survey in Little Rock, Arkansas. Based upon the review of the core, Standard Lithium selected 18 samples for porosity and permeability analysis to verify historical measurements.

The core analytical test work was conducted over the course of 4-decades from 1942 to 1987. Geotechnical data presented in this Technical Report include core reports that were prepared by independent petroleum engineering firms that include: Core Laboratories Inc. in Dallas, TX and Shreveport, LA; Delta Core Analysts in Shreveport, LA; All Points Inc. in Houston, TX; Thigpen Laboratories, Inc. in Shreveport, LA: O'Malley Laboratories, Inc. in Natchex, MS; and Bell Core Laboratories in Shreveport, LA.

The average porosity and permeability measurements from the Property of 515 core plug samples are 10.2% and 53.3 millidarcies (mD), respectively. Measurements from the 1,110 core plugs from the 22 wells surrounding the SWA Property yielded an average porosity and permeability measurements from the Property of 8.6% and 64.6 mD, respectively.

Figure 9-3. Top of Buckner Formation Structure Map.



9.2 2018 Brine Sampling Program

To verify the historical lithium concentrations in the brine (Section 6.2) Standard Lithium conducted a brine sampling program at the following McKamie-Patton wells: MKP#20 brine sample collected on June 22, 2018; and MKP#21 brine sample collected on July 23, 2018.

The locations of the McKamie-Patton wells are shown on Figure 9-4 and Table 9-1 summarizes the lithium laboratory analytical results. Two of these wells, MKP#20 and MKP#21, are completed in the Upper Smackover Formation.

Table 9-1. Summary of analytical results from 2018 sampling program.

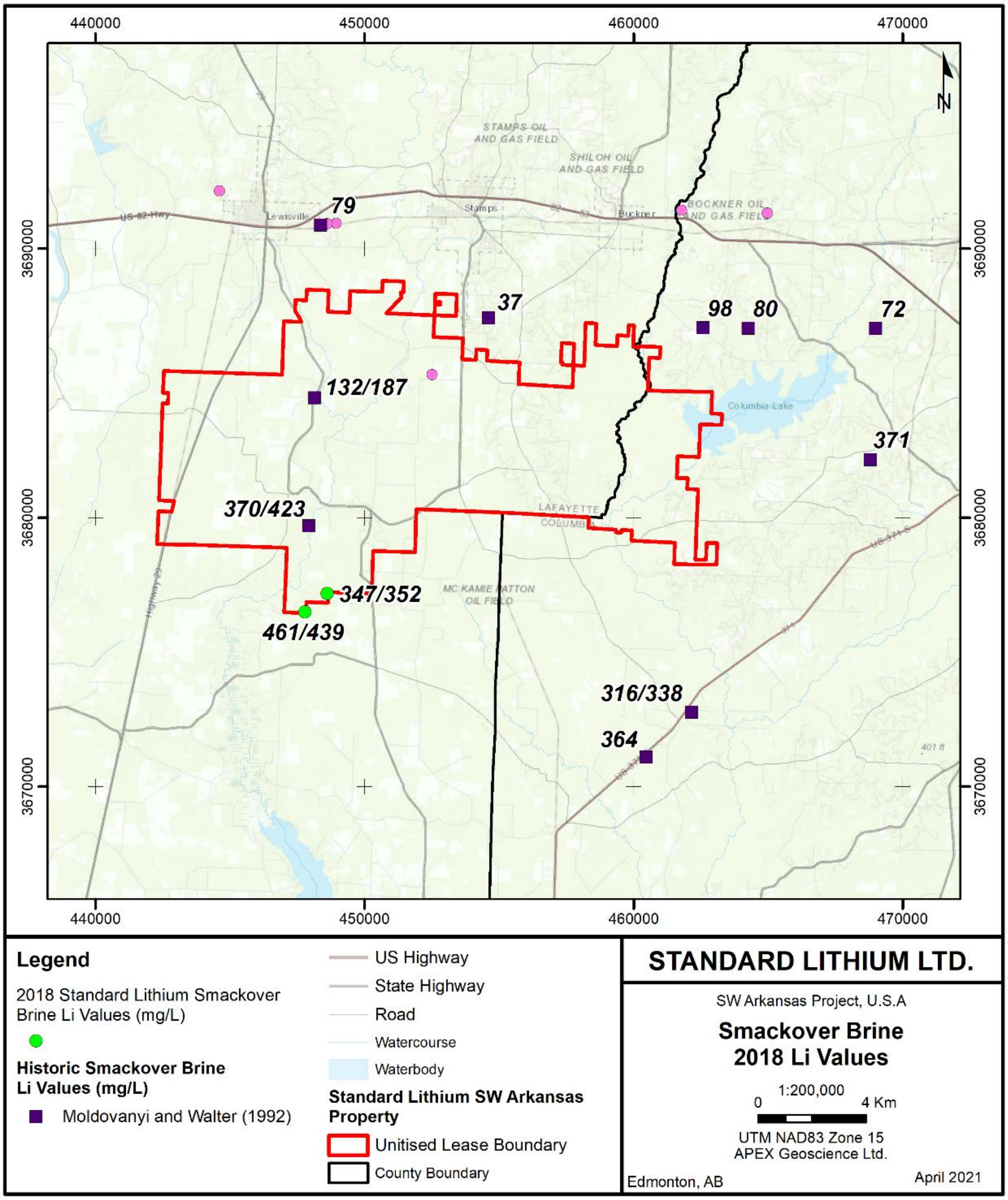
Well/Sample ID	Latitude	Longitude	Dominion Land System	Total well depth (m)	Well status	Lab	Li (mg/L)
MKP-20-1B	33.23241	-93.55148	35-17S-24W	2,885	Prod.	WetLAB	347
MKP-20-1B	33.23241	-93.55148	35-17S-24W	2,885	Prod.	WetLAB	352
MKP-20-1	33.23241	-93.55148	35-17S-24W	2,885	Prod.	ALS-H	265
MKP-20-1B	33.23241	-93.55148	35-17S-24W	2,885	Prod.	ALS-H	302
MKP-21	33.22617	-93.56029	35-17S-24W	2,860	Prod.	WetLAB	461
MKP-48 (dup of MKP-21)	33.22617	-93.56029	35-17S-24W	2,860	Prod.	WetLAB	439
MKP-21	33.22617	-93.56029	35-17S-24W	2,860	Prod.	ALS-H	380
MKP-48 (dup of MKP-21)	33.22617	-93.56029	35-17S-24W	2,860	Prod.	ALS-H	425
						Average (all data)	371
Prod. - Well is currently producing oil						Average MKP-20 (all data)	317
						Average MKP-21 (all data)	426
						Average MKP-20 (WetLab)	350
						Average MKP-21 (WetLab)	450

Standard Lithium uses WetLab and ALS-Houston as their primary and secondary laboratories (see discussion in Section 11). The reader is referred to Section 11.5, Quality Assurance – Quality Control, for discussion on the designation of WetLab as the primary laboratory, and rationale for WetLab analytical results being deemed appropriate by the author for use in the resource estimation.

WetLab laboratory analyses of the brine samples measured an average lithium content of 350 mg/L and 450 mg/L, from wells MKP#20 and MKP#21, respectively (Table 9-1). The lithium concentrations obtained by Standard Lithium in the brine from wells MKP#20 and MKP#21 are similar to the historical Property results from Cornelius 1 (432 mg/L) and Cornelius 2 (370 mg/L; Moldovanyi and Walter, 1992). Cornelius 1 and 2 are located approximately 3 kms (2 miles) to the north of MKP#20 and #21 as shown in Figure 9-4.

The 2018 Standard Lithium laboratory results validates the historical data of Moldovanyi and Walter (1992) and verifies the presence of lithium-enriched brine within the Smackover Formation underlying the SWA Project.

Figure 9-4. Location of brine samples collected by Standard Lithium as part of the 2018 brine sampling program as well as historical lithium results.



10 DRILLING

The issuer of this Technical Report, Standard Lithium, has yet to drill any wells at the SWA Project. Standard Lithium does, however, have access to Mission Creek Resources oil wells located on the Property and two wells, MKP#20 and MKP#21 were accessed by Standard Lithium to obtain brine samples. As this work is directly related to geochemical exploration work, the reader is referred to Section 9.2, 2018 Brine Sampling Program to view the sample locations (Figure 9-6) and analytical results. Additional well information and brine access points is discussed in the text that follows.

The wells MKP#20 and MKP#21 were drilled by The Carter Oil Company as oil wells in 1955 and 1956, respectively. The AOGC list that both wells are currently active and producing oil from within the McKamie Patton Smackover Unit (AOGC, 2019). In September 2018, the operator changed from Bonanza Creek Energy Resources, LLC to Mission Creek OPCO, LLC. Both wells (MKP#20 and MKP#21) were drilled vertically with an orientation and dip of 0º and -90º.

The Mission Creek oil well completion intervals – and brine collection access points – are as follows:

- MKP#20 – 2,840 to 2,871 m (9,317 to 9,419 feet) below ground surface; and
- MKP#21 – 2,825 to 2,831 m (9,270 to 9,287 feet) below ground surface and the well was perforated in September 2018 at 2,825 to 2,786 m (9,267 to 9,139 feet; AOGC, 2019).

The total depths of MKP#20 and MKP#21 wells are 2,885 and 2,860 m, respectively (AOGC, 2018). Hence the brine was taken close to the total depth of each well. This is not unusual in southern Arkansas because the oil and gas essentially produced, and hence targeted, the porous portions of the Upper Smackover Formation. As per the cross-sections presented in Section 9.1, the Middle Smackover Formation was penetrated less seldom, but can comprise oil-bearing porous reservoirs.

The author concludes the MKP#20 and MKP#21 well sample points were in Upper Smackover Formation. A review of the well log data supports this hypothesis (e.g., see Figure 7-6 and the MKP#21 well on cross-section A-A'). Lastly, the horizontal location of the Standard Lithium brine samples was confirmed as Upper Smackover Formation in the 3D model created as part of the resource estimation presented in this Technical Report (Section 14.3, Geometry of the Upper and Middle Smackover Formation Domain).

11 SAMPLE PREPARATION, ANALYSES AND SECURITY

11.1 Brine Sample Collection

Brine samples were collected from existing oil wells from Mission Creek Resources (Section 10). A critical step to sampling brine for geochemical analysis is to ensure that the brine collected is considered "fresh brine" representative of Upper or Middle Smackover Formation and has not been stagnant in the wellbore.

During the 2018 sampling programs conducted by Standard Lithium, Mission Creek staff assisted with the sample collection. The sample collection methodology included:

- Review the well construction schematic to assess total depth, perforation zone, and production casing diameter. The existing production tubing and packer assembly was removed. A new packer assembly was installed immediately above the perforated zone. New production tubing was also installed in the well. All the work was completed by a workover rig as shown in Photo 11-1.
- The volume of brine in the production casing below the packer and within the production tubing was calculated. The volume of brine in the production casing and tubing represents the stagnant brine within the well that must be removed to allow fresh formation brine to enter the well prior to sample collection.
- Fluids (brine>>>oil) were removed from the well by swabbing the production tubing. Swabbing involves lowering swab cups on steel wireline inside the production tubing from above the perforations. Once the wireline and swab cups were lowered to the desired depth through a fluid column of approximately 100 m (300 ft) there were raised, and the entire 100 m (300 ft) column of fluid was brought to wellhead and conveyed to a mud tank for storage through a piping system. The volume of fluid removed from the well was calculated based upon the volume measured at regular intervals in the mud tank. Swabbing of the well was continued until approximately 2 volumes of stagnant fluid/brine was removed.
- Field measured parameters were collected onsite by a Baker Petrolite representative to assess brine density and chloride concentration at regular intervals after 1.5 volume of stagnant fluid had been removed from the well. Field measured parameters were compared to known values of the Smackover Formation. The formation has a brine density of about 1.20 grams/cubic centimeter (10.2 lbs/gallon) and contains 170,000 to 200,000 mg/L of chloride. Brine was removed from the production tubing by swabbing. Swabbing continued until at least 2 stagnant volumes had been removed and field measured parameters were within the typical range of the Smackover Formation.
- Brine established to be from the Smackover Formation (based on density and chloride content) was collected by filling two 20 L (4.4 imperial gallons) plastic carboy containers from a valve installed at the wellhead. Safety protocols were exercised on site due to the hydrogen sulphide (H_2S) gas content associated with the produced Smackover Formation fluids. The carboy containers were kept still for about 1 to 5 hours to allow oil and brine to separate if oil was present. In all cases only a very thin film of oil was observed in the carboys attesting to the high brine to oil ratio.
- New laboratory-supplied 1-litre plastic sample containers with screw-on caps were labelled using Standard Lithium's label procedure that includes recording the: sample identification; date and time of sample collection; and sampler's initials.

- The plastic sample containers were placed under the well sample spigot and a small amount of brine was captured, swirled in the container and discharged. Rinsing the sample containers was completed twice to ensure that the container is clean and free of any residue that might affect the analysis. The procedure also established a 'brine flow' such that stagnant brine was discharged prior to the sample collection.
- The plastic sample container was filled to capacity, or near-capacity where it was immediately capped tightly with a screw-on cap.
- The physical attributes of the brine sample were recorded (e.g., colour, smell, contaminants, etc.). The sampling process is completed by recording any comments that might be significant to the sampling site, the sample collection or the sample itself.
- Three 1-litre sample containers were taken by Standard Lithium at each sample point; 2 containers for geochemical analysis at independent laboratories, and 1 sample container for Standard Lithium's archival storage (at a locked storage centre in El Dorado, AR).
- The sample containers were checked to verify that all sample label information was correct, and the sample container was properly closed. All sample containers were then stored in a cooler for shipping to the laboratories.

11.2 Field Duplicate Samples and Semi-Certified Standard Samples

A field duplicate sample was collected for every sample (n=4 original and 4 duplicate samples). The field duplicate sample was taken at the same time as the original sample (i.e., back-to-back samples from the brine sample spigot). Random identifiers were given to the duplicate sample; i.e., the original and duplicate field samples were never in sequential order and randomly presented to the laboratories.

To the best of the author's knowledge, Certified Lithium-Brine Sample Standards, which have a special classification and are subject to rigorous international testing, do not currently exist. As part of Standard Lithium's Quality Assurance/Quality Control (QA/QC) measures, the Company commissioned the University of British Columbia to prepare a 'semi-certified sample standard' by adding a measured amount of elemental lithium (in this test, 250 mg/L of lithium) to saline brine with a TDS content of 250,000 mg/L (TDS to simulate brine). The semi-certified standards were inserted randomly into the sample stream. The purpose of the semi-certified sample standard samples was to measure the accuracy of the laboratories and the results are discussed in Section 11.5, QA/QC.

Photo 11-1. Sampling setup at Mission Creek MKP#20 well.

11.3 Security

Coolers full of sample containers were taken from the field to a secured location to double check the sample IDs and make sure all containers are in good condition prior to shipment to the laboratory. Chain of Custody forms for the respective laboratories were filled out and included with the sample cooler.

The cooler was taped closed and hand-delivered to the local courier company (Fed-Ex in El Dorado, AR) for rush delivery to the laboratories, which include: ALS-Houston in Houston, TX; and WetLab in Sparks, NV. The laboratories were instructed to confirm receipt of the samples and provide a statement pertaining to the condition of the samples upon receipt. The samples were then coded into the respective laboratories sample stream for analysis.

11.4 Analytical Methodology

Standard Lithium has prepared its own internal analytical protocols for the independent laboratories to follow. These include the following analytical work (with the associated American

Society for Testing and Materials (ASTM), Standard Methods (SM) and Environmental Protection Agency (EPA) international and national method code):

“Limited Lithium Brine Analytical Suite”

- General chemistry: density, pH, carbonate, bicarbonate, total dissolved solids (ASTM 1963, SM 4500-H+B, SM 2320B and SM 2540C).
- Anions by Ion Chromatography: chloride, sulfate (EPA 300.0)
- Sample preparation: trace metal digestion (EPA 200.2)
- Trace metals by inductively coupled plasma optical emission spectroscopy (ICP-OES): Li, Ba, B, Ca, Fe, Mg, Mn, K, Na, Sr (EPA 200.7)

“Expanded Lithium Brine Analytical Suite”.

- General chemistry: density, pH, temperature, carbonate, bicarbonate, total dissolved solids, total organic carbon (ASTM 1963, SM 4500-H+B, SM 2550B, SM 2320B, SM 2540C and SM 5310B).
- Anions by Ion Chromatography: chloride, sulfate, bromide, fluoride (EPA 300.0)
- Sample preparation: trace metal digestion (EPA 200.2)
- Trace metals by ICP-OES: Li, Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Ga, Fe, Pb, Mg, Mn, Mo, Ni, P, K, Sc, Se, silicon, silica, Ag, Na, Sr, Sn, Ti, V and Zn (EPA 200.7)

ALS-Houston completed this analysis using the following corresponding methods: ICP-MS Metals by SW 6020A; Conductivity by E120.1; anions by E300.0; total dissolved solids by SM 2540C; alkalinity by SM 2320B; density by 2710F; dissolved silica by SM 4500-SID; and pH by SW 9040C.

WetLab completed these analyses using the following corresponding methods: sample preparation by EPA 200.2; density by gravimetric; pH by SM 4500-H+B; temperature at pH by SM 2550B, carbonate and bicarbonate by SM 2320B; chloride and sulfate by EPA 300.0; total dissolved solids by SM 2540C; anions by ion chromatography by EPA 300.0; trace metal digestion by EPA 200.2; and trace metals by ICP-OES by EPA 200.7.

It is notable that the two labs used different analytical ICP instrumentation: ALS-H used inductively coupled plasma mass spectrometry (ICP-MS) and WetLab used inductively coupled plasma optical emission spectroscopy (ICP-OES). ICP-MS: measures an atom’s mass by mass spectrometry; detection limit can extend to parts per trillion (ppt). ICP-OES measures excited atoms and ions at the wavelength characteristics; lower limit is parts per billion (ppb). In the U.S., the regulatory compliance monitoring for ICP-OES is governed by EPA Methods 200.5 and 200.7. EPA Method 200.7 was approved for use as axial view of ICP-OES and is therefore the EPA method for compliance monitoring by ICP-OES. EPA Method 200.8 governs regulatory compliance using ICP-MS.

11.5 Quality Control/Quality Assurance

11.5.1 Field Duplicate Samples

Brine samples were collected from MKP#20 and MKP#21 wells in 2018. Of the four total field duplicates, two were sent to ALS-Houston and two to WetLab. The lithium results of the duplicate sample analyses are presented in Table 11-1. The duplicate sample relative percentage difference (RPD) for WetLab was 1.4 % to 4.9 % and ALS was 11.2% to 13.4%. These results indicate that WetLab had a higher level of precision in their internal ICP metal analysis in comparison to ALS. It should be noted that any result with an RPD less than 20% is considered acceptable.

Table 11-1. Comparison of field duplicate samples from the 2018 sampling program.

A) WetLab duplicate pair analytical results

Well/Sample ID	Li (mg/L)	Well/Sample ID	Li (mg/L)
MKP-20-1B	347	MKP-21	461
MKP-20-1B	352	MKP-48	439
Mean	350	Mean	450
Standard deviation	4	Standard deviation	16
RSD%	1.01	RSD%	3.46

B) ALS-Houston duplicate pair analytical results

Well/Sample ID	Li (mg/L)	Well/Sample ID	Li (mg/L)
MKP-20-1	265	MKP-21	380
MKP-20-1B	302	MKP-48	425
Mean	284	Mean	403
Standard deviation	26	Standard deviation	32
RSD%	9.23	RSD%	7.91

Field duplicate results provide important information about the homogeneity of the sample medium and the representativeness of the sampling method employed. Data quality of the duplicate pairs is assessed using average percent relative standard deviation (also known as the % coefficient of variation or average RSD%) as an estimate of precision or reproducibility of the analytical results. The average RSD% is determined from the duplicate results by calculating the mean and standard deviation of each duplicate pair and then by dividing the standard deviation by the mean.

Generally, average RSD% values below 30% are considered to indicate very good data quality; between 30 and 50%, moderate quality and over 50%, poor quality. The higher an average RSD% value is, the less likely it is to be able distinguish real patterns from noise.

The duplicate pair analysis conducted at WetLab yielded excellent RSD% values of 1.0 and 3.5% (Table 11-1). Albeit having slightly higher RSD% values, ALS-Houston duplicate pair analytical results was also excellent (<9.2%).

11.5.2 Semi-Certified Standard Sample Comparison

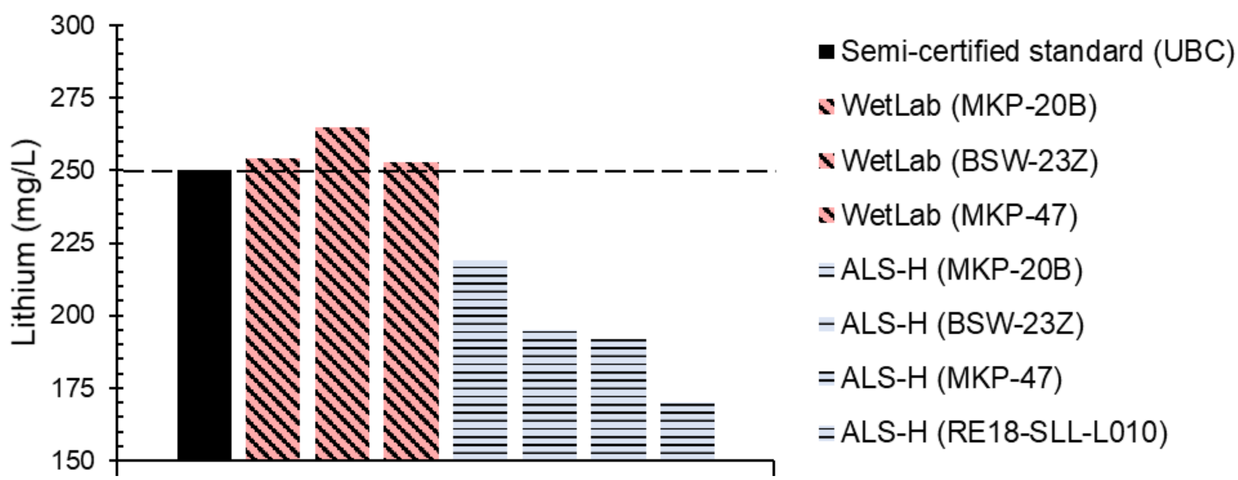
To further evaluate brine analytical accuracy, Standard Lithium conducted a laboratory comparison using a semi-certified sample standard. The semi-certified sample standard was designed to be similar to Smackover Formation brine from the SWA Project. The semi-certified standard sample was prepared by the University of British Columbia, on behalf of Standard

Lithium, and has a lithium content of 250 mg/L in a high TDS brine. The salts used were >99% analytical purity and include (with cation concentration equivalents): calcium chloride ($CaCl_2 \cdot 2H_2O$ - 30,000 mg/L Ca); lithium chloride (LiCl 250 mg/L lithium); magnesium chloride ($MgCl_2 \cdot 6H_2O$ - 2,500 mg/L Mg); potassium chloride (KCl - 2,000 mg/L K); sodium chloride (NaCl - 60,000 mg/L Na); and strontium chloride ($SrCl_2 \cdot 6H_2O$ - 2,000 mg/L Sr) (Dr. J. Hein, personal communication, 2018).

A total of six semi-certified sample standards were randomly inserted into the sample stream by Standard Lithium; three standards to WetLab and three to ALS-Houston. A single semi-certified sample standard was inserted by Roy Eccles as part of the QP site inspection brine samples (analysed at ALS).

Figure 11-1 shows that WetLab ICP-OES analyses performed better on the semi-certified sample standard in comparison to ALS ICP-MS. The WetLab data were within 1% to 6% of the semi-certified sample standard. Alternatively, the ALS-Houston data underestimated the semi-certified sample standard lithium content by 12% to 32%. This test supports the use of WetLab as the primary lab and WetLab data as the primary dataset used in this resource estimate.

Figure 11-1. Histogram of the semi-certified sample standard that was analysed at WetLab and ALS-Houston.



11.6 Other Data: Core Reports

Historical core reports include pertinent information on Upper and Middle Smackover formations core measurements conducted by independent engineering consultants (Core Laboratories Inc. in Dallas, TX and Shreveport, LA; Delta Core Analysts in Shreveport, LA; All Points Inc. in Houston, TX; Thigpen Laboratories, Inc. in Shreveport, LA: O'Malley Laboratories, Inc. in Natchex, MS; and Bell Core Laboratories in Shreveport, LA). These reports included core measurements that included porosity (%) and permeability (mD) on 1,625 core samples from throughout and immediately surrounding the SWA Project. Some of the core report data also includes: data for oil% in pore space; water% in pore space; bulk oil%; bulk gas%; bulk water%; and vertical permeability.

In general terms, the historical porosity and permeability measurements were obtained for every foot of conventional core. Horizontal permeabilities were measured on each drilled plug using a steady state permeameter with nitrogen as the measuring media and a confining pressure of 350 psi. Two wells also measured vertical permeability on a total of 51 samples.

11.7 Summary

These analytical brine and core report data were prepared by independent and accredited third-party companies. The resulting quantitative data are used to make inferences on the brine analytical values and hydrogeological characteristics of the Upper and Middle Smackover formations aquifer. The analytical methods carried out by the laboratories is standard and routine in the field of lithium brine geochemical analytical and petrophysical core characterization test work.

The author has reviewed the adequacy of the sample preparation, security and analytical procedures and found no significant issues or inconsistencies that would cause one to question the validity of the data. While the number of sample data are presently minimal, the QA/QC protocol adopted by Standard Lithium helped the author to evaluate and validate the laboratory data as discussed in Section 12, Data Verification.

12 DATA VERIFICATION

Data verification procedures were applied by the QP on all data pertaining to the resource model and estimate (Section 14) presented in this Technical Report. This information as it pertains to the SWA Project includes: 1) historical and/or publicly available data; 2) new interpretations derived from historical and/or publicly available data; and 3) new information such as laboratory analysis. These data and our data verification procedures are discussed under the following titles (in bold; non-headers).

Subsurface LAS Logs: Subsurface well data were acquired from three different third-party and Government sources: 1) IHS Markit; 2) Arkansas Oil and Gas Board; and 3) ARK-LA-TEX Log Library Inc. A total of 104 wells had electric logs in the SWA Property and surrounding area. Once geocoded into the proper coordinates space, the existing stratigraphic picks were reviewed for accuracy on a well-by-well basis. The top of Smackover Formation picks was usually precise, where the stratigraphic picks were off, the picks were revised by Hill Geophysical Consulting in collaboration with Mr. Eccles. The bottom of the Upper Smackover Formation was almost never picked, and hence, this was newly created information specific to this Technical Report.

Subsurface Core Report Total Porosity and LAS Total Porosity Logs: The individual core reports were reviewed against the original LAS logs to confirm that the depths of the core intervals matched the depth of the Upper and Middle Smackover formations on the log files. No errors were found. Pertinent data such as porosity and permeability information from the core reports were converted from hardcopy to electronic files by APEX under the supervision of the author.

With respect to the LAS porosity logs, 29 wells had density logs that could be used for total porosity calculations of the Upper and Middle Smackover formations. Nineteen of the density logs penetrated then entire thickness of the Upper Smackover Formation. The LAS porosity logs were not used in this evaluation as a large percentage of total porosity values were negative. See Sections 24.3.2 and 25.3 for an analysis of the total porosity derived from the density logs and recommendations for Standard Lithium to utilize the LAS porosity logs in the future.

SWA Property Infrastructure: Roy Eccles P. Geol. conducted a site inspection of the SWA Property on March 5 to 9, 2018. The site visit validated the Property and observed active exploration at the Property in the form of using oil and gas infrastructure to obtain brine samples for analytical testing. Roy Eccles also viewed the existing oil and gas infrastructure including primary and secondary road network and the McKamie-Patton oil and gas field including well sites, pipeline corridors and gas plant.

Laboratory Analytical Data: The author investigated Standard Lithium's 2018 analytical results. It is the author's opinion that the ICP-OES method EPA 200.7 is best suited for brine analysis and use in the resource estimate presented in this Technical Report. ICP-OES has a higher tolerance for total dissolved solids (up to 30%). ICP-MS has a lower tolerance for total dissolved solids (about 0.2%; although there are ways to increase the tolerance such as high matrix introduction / aerosol dilution; e.g., Wahlen, 2011; ThermoFisher Scientific, 2018). ICP-MS can have a limited tolerance to total dissolved solids where: frequent calibrations are required; long-term stability can be compromised; and samples must be diluted significantly prior to analysis. If samples with very high total dissolved solids levels are run, the orifices in the cones will eventually become blocked, causing decreased sensitivity and detection capability, and requiring the system to be shut down for maintenance; consequently, several sample media types must be diluted before running on the ICP-MS (Wolf, 2005). This collectively can cause greater likelihood in bias in results.

The author has reviewed all geotechnical and geochemical data and has found no significant issues or inconsistencies that would cause one to question the validity of the data. In addition, the 2018 brine sampling conducted by Standard Lithium provides verification of the historical brine analytical results of Moldovanyi and Walter (1992). In fact, a comparison between the two datasets yields an RSD% value of 12% that indicates good correlation (Table 12-1).

Table 12-1. Comparison of analytical Lithium results from Standard Lithium's 2018 sampling program (original and field duplicate samples) and historical results from Moldovanyi and Walter (1992).

Well/Sample ID	Li (mg/L)	Source
MKP-20-1B	347	Standard Lithium (this report)
MKP-20-1B	352	Standard Lithium (this report)
MKP-21	461	Standard Lithium (this report)
MKP-48	439	Standard Lithium (this report)
Cornelius 1	423	Moldovany and Walter (1992)
Cornelius 2	370	Moldovany and Walter (1992)
Mean	399	
Standard deviation	49	
RSD%	12.17	

The review of third-party, government and/or data was conducted or discussed during team working sessions. The QP's of this Technical Report can confirm that the data was generated with proper procedures, has been accurately transcribed from the original source and is suitable for use in this Technical Report.

Lastly, based on Roy Eccles' previous experience and research of lithium-brine deposits, and sampling and analytical protocols, Mr. Eccles, P. Geol. is satisfied to include these data in resource modelling, evaluation and estimations as part of SWA Project lithium-brine resource estimate presented in this Technical Report. This opinion includes a QP acceptance of using the historical geochemical data of Moldovanyi and Walter (1992) in the resource estimation process.

12.1 Metallurgical Test Data

NORAM's preliminary design of the processing facility (described in Sections 13 and 17) is based on results obtained from Standard Lithium's operating Demonstration Plant testing their DLE process. Samples produced in the Demonstration Plant, were analysed with the same methods described in Sections 11.4.

NORAM reviewed the sample analyses provided by WetLab and ALS-Houston, laboratory procedures and certifications, where applicable. The test procedures are appropriate for the testwork requirements, and the results support the development of the preliminary process design. The testwork results were sufficiently detailed and the reported selectivity for lithium and rejection of other metallic species were in-line with expectations when compared to that of competing technologies.

13 MINERAL PROCESSING AND METALLURGICAL TESTING

13.1 Introduction

Standard Lithium is developing a flowsheet that can selectively extract lithium from Smackover Formation brine at the Company's SWA Project and produce battery-quality lithium chemicals. The mineral processing and hydrometallurgical flowsheet consists of three process areas:

1. Pretreatment of the brine to remove separate gaseous and non-aqueous phase liquids (oils and/or natural gas condensates) from the brine at the wellhead, combined with any suspended solids removal prior to lithium extraction. These processes are industry-standard when handling produced waters from oil and gas fields and require minimal project tailoring or process adaptations;

2. Selective extraction of lithium from the brine using the Company's proprietary Direct Lithium Extraction (DLE) technology known as LiSTR to produce a purified and concentrated lithium chloride solution; and,

3. Conversion of the lithium chloride solution to lithium hydroxide through an electrochemical process, followed by evaporation and crystallisation of a high-purity lithium hydroxide solid product.

With regards to Process Area 1, the SWA Project is located in a region with abundant current oil and gas operations, and as such, there are multiple service providers who can tailor existing service offerings to effectively pre-treat the brine prior to delivery into the LiSTR DLE plant. Therefore, no additional technological development or proof is required at this stage of the project.

With respect to Process Area 2, the Company has been successfully running a LiSTR pre-commercial Demonstration Plant at the nearby Lanxess facility since May 2020. As a result, it has gathered significant data regarding the performance of the LiSTR technology on Smackover brines and has produced significant quantities of purified and concentrated lithium chloride solution.

With respect to Process Area 3, the Company is relying on previous hydrometallurgical and electrochemical testwork completed by NORAM. The process has been tested for over 1,000 hours with brines at small scale and will be operated in an electrolyser used at commercial scale for lithium sulphate electrolysis and now being modified for lithium chloride. The electrolysis process is similar to the conventional chloralkali technology for converting sodium chloride to sodium hydroxide.

13.1.1 Process Selection Rationale

Standard Lithium's SWA lithium-brine project has several unique aspects that require a different approach to processing lithium-bearing brine, as compared to traditional South American salar-based projects. The factors, which affect the selected approach, include the following:

- The climate and terrain in south western Arkansas are not conducive to the construction and operation of traditional solar evaporation ponds. Despite the high average annual temperature (23.5°C), the average humidity is too high (annual rainfall of 126.7 cm [50 in]); hence, the net solar evaporation rate is inadequate for operation of a traditional solar evaporation pond system. In addition, because there is little flat ground in the area, high capital investment costs for evaporation pond construction would be required;

- Tail-brine re-injection into the Smackover Formation is needed to maintain aquifer pressurization. Bromine recovery from the aquifer brine has been taking place in the general southern Arkansas region for over 60 years. As a result, changing the process to solar evaporation ponds would negatively affect the water balance in the Smackover Formation beneath the Project area; and
- The Smackover Formation brines have much higher background levels of alkaline earth elements compared to brines typically found in salars exploited for lithium recovery in South America.

Conversely, the Southern Arkansas area and the project site have several attributes that are not commonly found at lithium brine development locations; these allow a wider range of lithium extraction and conversion processes to be considered. These project attributes include the following:

- Existing brine processing businesses (LANXESS and Albemarle bromine plants). There is a local workforce well versed in pumping, processing and reinjecting very large volumes of brine, combined with a well-understood regulatory framework;
- Access to abundant fresh water for use in chemical processes;
- Immediate access to stable, high capacity and relatively inexpensive electricity;
- Excellent access to low-cost, standard chemical reagents (acids, bases etc.); and,
- Excellent access to low-cost gas for any required thermal processes.

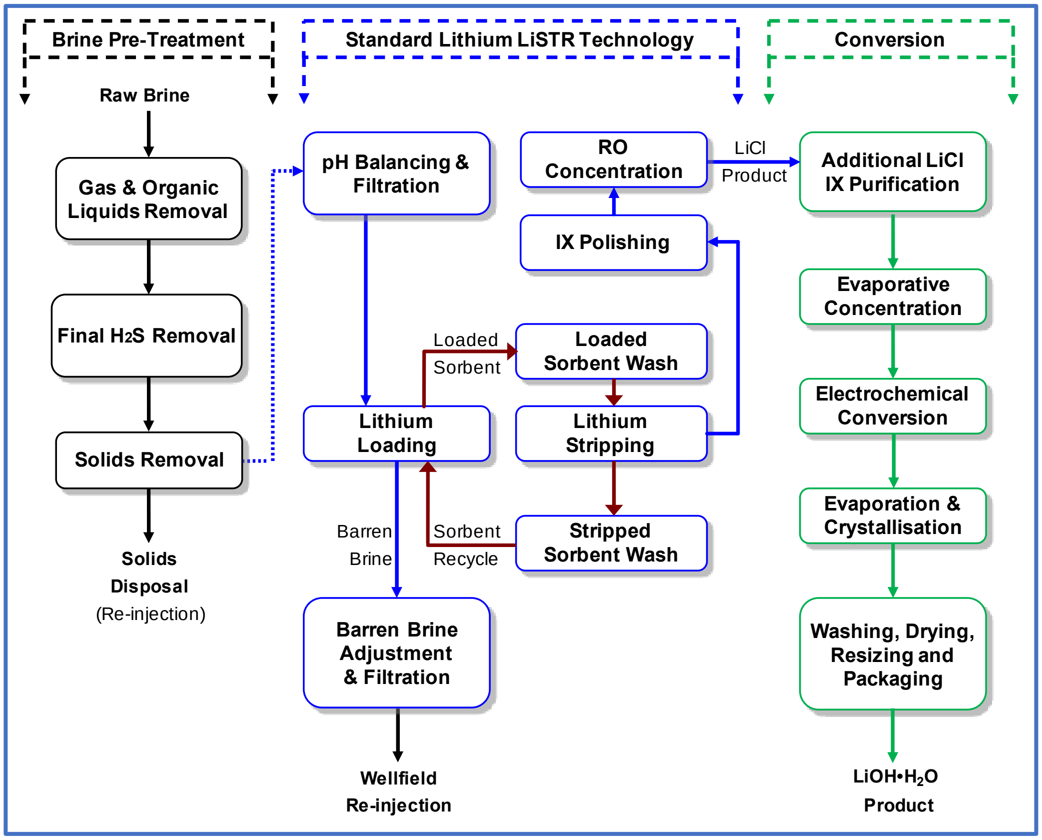
13.1.2 Process Overview

As discussed above, the initial pretreatment of the brine to remove dissolved gasses, any co-produced liquid hydrocarbons and any suspended solids will use industry-standard techniques, similar to those already used at large scale in southern Arkansas at the active brine processing businesses (e.g. at LANXESS or Albemarle's operations), or as part of produced-water management associated with oil and gas production in the region.

Based on the work completed by Standard Lithium to date, the company expects to use its proprietary LiSTR DLE technology to extract lithium from the Smackover Formation brine and produce a concentrated and purified intermediate lithium chloride solution. This technology has been in pre-commercial operation and optimization since May 2020 at the Company's Demonstration Plant located on one of LANXESS's facilities in Union County, AR. This technology is sufficiently tested and validated that it can be reasonably considered for use in the SWA Project. The conversion of the intermediate lithium chloride solution into a lithium hydroxide solution using an electrochemical process is based on technology developed and tested by NORAM at their testing facilities in Richmond, BC. Final concentration and crystallisation of lithium hydroxide monohydrate ($LiOH{\bullet}H_2O$) will use industry standard equipment and process technology.

Figure 13-1 is a simplified schematic showing the main process steps proposed for the SWA Project.

Figure 13-1 SWA Lithium Brine Project Flowsheet Schematic



The intent of this Section is to discuss the South West Arkansas Li-brine mineral processing test work in accordance with CIM Best Practice Guidelines for Mineral Processing (2011). The level of definition is appropriate to the confidence categories of mineral resources being supported and the current stage of project development.

It is the opinion of the author preparing this section, that the discussion includes an objective level of reasonableness and demonstrates competence and due care in the execution of the metallurgical testwork and lithium-brine recovery process steps.

13.2 Historical Testing

To the best of the author's knowledge, no historical testing regarding lithium recovery from the SWA Project has been performed. All testing discussed below was performed for Standard Lithium as part of the current development program.

13.3 Brine Pre-Treatment Testing

As part of operating the pre-commercial Demonstration Plant at the LANXESS South Plant facility, several of the proposed pre-treatment processes have been demonstrated as part of normal operations at the facility. These include all wellhead operations to remove non-aqueous phases, removal of residual dissolved hydrogen sulphide (H_2S) prior to processing, bulk pH control, temperature adjustment and final filtration (prior to lithium extraction) using submerged membrane units.

As such, no additional pre-treatment testing is required for assessing the SWA Project.

13.4 LiSTR Demonstration Plant Testing

13.4.1 Overview

Standard Lithium has independently developed a technology to directly extract lithium from high TDS brines using a selective solid sorbent based on lithium titanate. This technology was initially developed in 2017 and went through two main scale-ups (each approximately a 100× scale-up) during 2018 and 2019. A large-scale Demonstration Plant, designed to be operated continuously, was designed and constructed in Ontario, Canada in 2019 by Zeton Inc. The plant, which consisted of 18 modules, was dismantled and transported to its current location at LANXESS' South Plant facility in Union County. To erect this operational brine processing facility, approximately 1 acre of land was levelled and prepared for installation (with all utility and brine connections) in late 2019. The plant was installed/connected and enclosed in late 2019/early 2020 and underwent commissioning in early 2020. The official start-date for the plant was during the second week of May 2020. The plant has been operating continuously (with the exception of normal or enforced shut-downs) since then. For this roughly 18-month period, the plant has been extracting lithium from Smackover Formation brine and producing a purified and concentrated lithium chloride solution. Some optimizations were made to the plant during December 2020, and in August 2021, an additional high pressure reverse osmosis (HPRO) unit was installed at the plant (the HPRO unit operation had, until that point, been completed off-site as an occasional batch process).

The Demonstration Plant has a dedicated team of engineers and operators who run the plant 24/7, as well as a separate analytical laboratory and chemist to complete all on-site process control assays. As the plant has abundant instrumentation and automation, large amounts of data are continuously generated. This is supplemented by a large and systematic sample and data collection schedule executed by the operators.

The Demonstration Plant has been continuously processing a slipstream of the tail-brine produced by the LANXESS South facility. The lithium-barren tail-brine and the vast majority of the lithium chloride produced, as well as added process water are continuously transferred back to the LANXESS brine disposal system. Representative analyses of two feed brines and the Demonstration Plant product raw lithium chloride (LiCl) solution are provided in Table 13-1.

Table 13-1. Representative Brine Analyses and lithium chloride Product

	Demonstration Plant brine supply	SWA Lithium Project	LiCl Product from Demonstration Plant
Lithium	245	415	5,390
Boron	195	302	251
Sodium	85,042	71,700	18,700
Potassium	2,775	6,670	304
Calcium	37,114	38,366	16
Magnesium	2,368	2,506	ND
Strontium	2,377	2,990	ND
Chloride	189,143	210,000	66,700
Sulphate	ND	ND	ND
Total Dissolved Solids	316,428	344,000	130,000

Notes:
[1] All units are mg/L
[2] Demonstration Plant brine composition is average of 7 samples collected from 27th May to 2nd June 2020
[3] SWA Lithium Project brine is average of MKP#20 and MKP#21 analytical results
[4] ND; not detected
[5] All samples were analysed at WetLab, NV

As can be seen from Table 13-1, the major element composition of the brine that has been processed through the Demonstration Plant is very similar to representative brines from the South resource area in the SWA Project. The brine that is provided by LANXESS to the Demonstration Plant is normally de-brominated (by LANXESS). However, there have been several periods when bromine extraction has not been occurring (for normal operational reasons), and the Demonstration Plant has received brine with >4,000 mg/L bromide; this is relevant for assessing how the SWA Project brines may behave in the LiSTR process.

As of the end of Q3 2021, the Demonstration Plant had processed 30,895 m^3 (8,161,350 US gallons) of brine.

Operations within the Demonstration Plant can be systematically varied, and as such, the effect of changing operating parameters on operational metrics such as degree of lithium recovery from the incoming brine, sorbent washing efficiency, the concentration of the strip solution or the composition of the final lithium chloride concentrate that is being produced by the LiSTR process can all be studied in a controller manner. As with any industrial process, there are many competing factors, and the optimal operation is typically a trade-off between the various inputs. For reference, a representative lithium chloride analysis is provided in Table 13-1, though this can be modified by varying the processes in the Demonstration Plant.

13.4.2 Findings from Demonstration Plant Testing

Key findings and outcomes from the LiSTR Demonstration Plant testing are:

- The process works well to selectively extract lithium from the Smackover Formation brine to produce a solution in which the lithium content has been significantly enriched relative to the other components of the feed tail-brine
- Pre-treatment of the incoming brine is necessary to remove dissolved gasses, non-aqueous phases and suspended solids;
- Initial bulk pH control can be performed upstream of the loading reactors;
- Continuous and accurate pH control in the loading reactors is critical to good performance;
- Loading efficiency (lithium extraction efficiency) is a direct function of sorbent capacity and mass flux vs brine flow in the loading reactors – this is a variable that can be controlled;
- Submerged membranes can be used effectively in the loading reactors to extract barren (lithium-free) brine, but their utility is limited at very high solids concentrations in the sorption slurries;
- The lithium-specific titanate-based sorbent has demonstrated excellent chemical and physical stability and has undergone several hundred loading and stripping cycles;
- Lithium loading capacity of fresh sorbent initially decreases over a few cycles but then has been found to remain stable with no further capacity loss over many operating cycles;
- Industry-standard counter current decantation (CCD) circuits can be used to wash the sorbent in either loaded or stripped (reactivated) state;
- Continuous and accurate pH control in the stripping reactor is critical to good performance and sorbent stability;
- The initial strip solution can be efficiently purified via standard (off the shelf) ion exchange (IX) resins, but using a novel and proprietary adaptation;
- Boron has been shown to be easily removed from the concentrated lithium chloride solution by third party work using OEM industry-standard IX technology;
- The barren brine is suitable for reinjection, and over 30,283 m^3 (8,000,000 US gallons) of barren brine have been successfully reinjected;
- The lithium extraction process is not measurably affected by the presence or absence of bromide in the incoming brine;
- The final lithium chloride concentrate is suitable for further conversion and has been converted to battery quality lithium carbonate via two different processes; and,
- Work is well underway to commercialise the production of the lithium titanate-based sorbent.

Design work is currently underway to scale-up the flowsheet and design a commercial facility.

13.5 Lithium Chloride Conversion Testing

The lithium chloride produced by LiSTR will undergo additional purification (by IX) and concentration (thermal/evaporation) prior to being converted to lithium hydroxide solution in an electrochemical process. The lithium hydroxide solution will then be concentrated to saturation and lithium hydroxide monohydrate crystals formed in the evaporator/crystalliser will be separated, dried (± resizing) and packaged in an inert atmosphere.

To date, no direct conversion of lithium chloride solution produced from the LiSTR process into lithium hydroxide has been carried out by the Company or by its technical consultants. However, NORAM have conducted several previous laboratory programs in a scalable electrolyser for other prospective lithium producers where similar lithium hydroxide (LiOH) conversion flowsheets have been tested. NORAM have completed several previous studies of lithium chloride to hydroxide conversion in a scalable reactor, and have achieved good results, in accordance with their expertise in electrochemical conversions.

It should be noted that the final concentration and evaporation/crystallisation of lithium hydroxide monohydrate is an industry-standard process and is practiced extensively at commercial scale.

13.6 Process Testing QA/QC

During the operation of the LiSTR Demonstration Plant, routine daily chemical analyses are conducted in the internal laboratory using standard solution analysis instrumental techniques; principally, atomic absorption spectrometry. For more important determinations, duplicate samples are submitted to SGS Canada Inc. (SGS) for analysis using their standard protocols (ISO 9000 compliant), developed based on their experience working on numerous lithium projects; principally, ICP-OES. Additional brine and solid samples are also periodically sent to other third-party analytical laboratories in order to provide suitable independent verification of data generated by the Demonstration Plant.

SGS Canada's laboratories and other qualified subcontractors have also provided services to characterize the sorbent used in the plant. The services included particle size analysis (Malvern Laser Particle Size Analyser), optical and scanning electron microscopy to look at particle morphology, and X-ray diffraction to determine crystal structure.

Other metallurgical testing, specifically settling tests, filtration tests and pulp rheology measurements, were carried out by SGS, Pocock Industrial, and on-site at the laboratory.

Other instrumentation in the Demonstration Plant undergoes a rigorous maintenance schedule to ensure accurate collection of data from the plant.

Throughout the process test work described, the author has had the following interactions:

- Visited the Zeton facility several times during construction of the LiSTR Demonstration Plant;
- Visited the installed Demonstration Plant during installation and early commissioning;
- Participated in twice-weekly video meetings throughout the entire operating period of the Demonstration Plant;

- Received daily data summaries regarding the operation of the Demonstration Plant and all analytical output;
- Participated in and oversaw much of the initial piloting and bench-scale testwork carried out at SGS;
- Involved in technical discussions and data sharing with the sorbent supplier for the commercial plant; and,
- Involved in scale-up discussions to date with engineering counterparties.

13.7 Process Scalability

As noted above, the pre-treatment portion of the flowsheet is industry standard technology and is already used at commercial scale in the southern Arkansas region. As such minimal scale-up risk is envisaged for this unit operation.

The LiSTR process has now been operated continuously for approximately 18 months at a pre-commercial Demonstration Plant scale. Whilst there is still considerable engineering work to complete to scale this to commercial operation, based on initial discussions with competent engineering and construction businesses, it is understood that all of the operations involved in the DLE process can be reasonably scaled-up.

Based on input from NORAM, referencing other lithium and sodium chemistries and test data, no significant issues are envisaged for scale-up of the electrochemical conversion and evaporation/crystallisation of lithium hydroxide monohydrate.

To date, no issues with process scale-up have been identified. It is feasible, and should not present any processing challenges, to divide the large flows into smaller parallel flows, should that be required for the full-scale plant.

13.8 Process Technical Risks and Mitigation Measures

Similar to all lithium brine processing projects (including those using ‘conventional’ evaporation ponds), there exist several risks that will need to be addressed or resolved as the project moves through the usual development stages:

- Security of sorbent supply – a large commercial supplier has been identified, and production of large batches of improved sorbent using commercial-scale production equipment are underway;
- Sorbent robustness – so far, the robustness and selectivity of the sorbent has been very encouraging, and operational parameters during the running of the Demonstration Plant (approximately 18 months) have and continue to be tuned to optimise its performance. However, the entire lithium recovery process is reliant on the long-term performance of this material, so its behaviour should be carefully monitored, preferably through longer-term operation of the Demonstration Plant. The Company is sourcing sorbent material domestically to be used in the Demonstration Plant;
- Effect of varying feed composition on loading – to date, the Demonstration Plant at the LANXESS facility has been operated with the South Plant brine feed (as shown in Table 13-1). However, the proposed brine feed (see also Table 13-1) does vary sufficiently that

its effect on lithium loading and selectivity should be confirmed. The LiSTR process will be tested on brine from the SWA Project; and,

- Lithium chloride to hydroxide conversion – whilst the technology required to convert lithium chloride to hydroxide is well understood, and analogous chlor-alkali technology has been operated at very large commercial scale for many decades, there are still likely hydrometallurgical and electrochemical subtleties that will need to be fully worked through for the Project's LiSTR feed composition. As such, a rigorous pilot programme to test this part of the flowsheet using real LiSTR lithium chloride solutions should be completed in the near term.

13.9 Conclusions and Recommendations

Standard Lithium has completed substantial testwork, and many aspects of the proposed flowsheet at the SWA Project are either normal industrial processes, have been demonstrated at substantial pre-commercial scale, or have been verified by pilot scale work on similar solutions. As such, it is felt by the author that sufficient testwork has been completed to support the flowsheet proposed for the SWA Project at this stage of evaluation.

Recommendations are:

- Continue to test and secure commercial-scale production of domestically produced sorbent material;
- Continue to operate and collect data from the existing LiSTR Demonstration Plant;
- Process large volumes of feed brine from the SWA Project location through the Demonstration Plant, and run the brine through the LiSTR process;
- Complete a Pilot testing program at sufficient scale to verify that lithium chloride to hydroxide conversion is reasonable. This should be completed using real LiSTR lithium chloride solutions; and,
- Complete any necessary OEM testing to ensure that lithium hydroxide solution can be reasonably concentrated and evaporated/crystallised to a battery-quality lithium hydroxide monohydrate product.

14 MINERAL RESOURCE ESTIMATES

14.1 Introduction

Standard Lithium's SWA Project is an early-stage exploration project. Spatially, the SWA Project has been divided into four sections for the resource modelling and estimation process. In plan view, the Property has been divided into North and South resource areas (Figure 14-1). The resources have been divided based on:

1) The authors geological evaluation of Jurassic stratigraphy underlying the SWA Project and discovery of an east-west-trending fault in the south-central part of the Project that has been used to divide the two resource areas (Figure 14-1; and see Section 7.4, Property Geology: Characterization of the Smackover Formation and Section 9.1, Subsurface Data Review); and,
2) Geochemical variations on either side of the fault zone, in which the South resource area has significantly higher lithium concentrations in comparison to the North resource area (Figure 14-1).

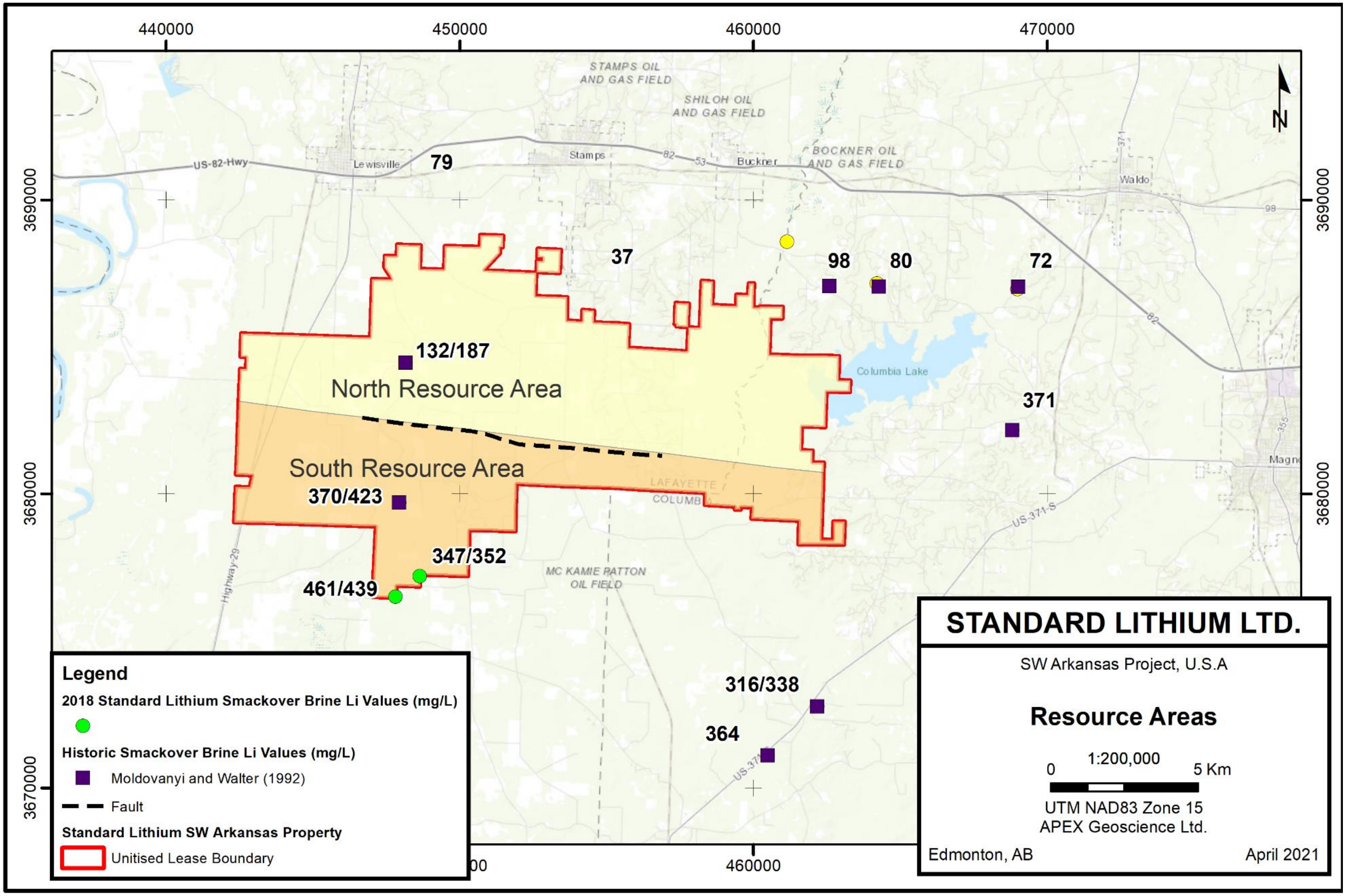
Horizontally, the resources are further divided into the Upper Smackover and Middle Smackover formations. Justification to split the two adjoining units is based on: 1) by stratigraphic nomenclature and definition such that the two units can be distinguished in electronic log profiles (see Section 7.4 Property Geology: Characterization of the Smackover Formation); and 2) both formations exhibit uniquely representative porosities, which is not atypical of a carbonate reservoir (Mazzullo and Chilingarian, 1992).

Accordingly, the SWA Property resource areas modelled and estimated a total (or main) updated SWA Property inferred lithium-brine resource estimate that considered, on an individual basis, the collective contribution from the:

- North Upper Smackover SWA lithium-brine resource area;
- North Middle Smackover SWA lithium-brine resource area.
- South Upper Smackover SWA lithium-brine resource area; and the
- South Middle Smackover SWA lithium-brine resource area.

The updated SWA Project inferred lithium-brine resource estimations were conducted in consideration of, and accordance with, NI 43-101 and: 1) CIM "Estimation of Mineral Resources and Mineral Reserves Best Practice Guidelines" dated November 29th, 2019; 2) CIM "Definition Standards for Mineral Resources and Mineral Reserves" adopted May 10th, 2014; and 3) CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brine (November 1st, 2012).

Figure 14-1. Definition of the North and South SWA Property Mineral resource areas. The fault dividing the two resource areas is inferred from this study, and presently, is the most plausible explanation for the variation of lithium-in-brine values between the south and north areas.



14.2 Resource Estimation Steps

Statistical analysis, three-dimensional (3-D) modelling and resource estimation was prepared by Mr. Black, M.Sc. P. Geo. of APEX (under direct collaboration and supervision of Mr. Eccles, M.Sc. P. Geol.). The workflow implemented for the calculation of the updated SWA Property inferred lithium-brine resource estimate was completed using: the commercial mine planning software MICROMINE (v 20.5).

Critical steps in the determination of the inferred North and South SWA Property lithium-brine resources include:

Step 1: Definition of the geometry and unitised volume of the Upper and Middle Smackover formations domain aquifers;

Step 2: Hydrogeological characterization of the confined Upper and Middle Smackover formations domain aquifers;

Step 3: A statistical calculation of the average effective porosity within the Upper and Middle Smackover formations;

Step 4: Consideration of the pore space fluid modal abundances (i.e., hydrocarbon versus brine);

Step 5: Determination of the concentration of lithium in the brine;

Step 6: Demonstrate that reasonable prospects of economic extraction are justified; and

Step 7: Estimate the *in-situ* lithium resources of Upper and Middle Smackover formations brine underlying the SWA Property Resource areas using the relation:

Lithium Resource = Total Volume of the Brine-Bearing Aquifer X Average Effective Porosity X Percentage of Brine in the Pore Space X Average Concentration of Lithium in the Brine.

14.3 Data

14.3.1 Subsurface Geophysical Wireline and Seismic Data

Subsurface well data were used to model the extent of the Upper and Middle Smackover formations. The information was acquired from three different sources: 1) Depth registered logs from IHS Markit (a software program that allows users to access raster and digital logs); 2) the AOGC; and 3) the ARK-LA-TEX Log Library Inc. The logs were scanned, and depth registered.

Summary statistics of the well data include:

- 2,444 wells have been drilled into the subsurface in the general SWA Property area.
- 2,041 wells were deep enough (2,135 m, or 7000 feet) to penetrate the Upper Smackover Formation.
- 104 wells had electric logs available within the SWA Property that included the top of the Upper Smackover Formation.
- 32 wells had electric logs available within the SWA Property that included the base of the Upper Smackover Formation.
- 19 wells had electric logs available within the SWA Property that included the base of the Middle Smackover Formation.

- 29 wells had density logs and/or porosity logs, 19 of which logged the entire Upper Smackover Formation.

Hardcopy prints of 20 proprietary regional seismic lines totaling over 200 line-km (over 125 line-miles) were procured, scanned, rasterized, and loaded into Kingdom® seismic and geological interpretation software. The seismic lines were corrected for time, phase, and amplitude.

14.3.2 Lithium Analytical Data

Lithium-brine analytical data pertinent to calculating an average lithium value for the Upper Smackover Formation include:

- North resource area: two historical analytical results in the North resource area (Moldovanyi and Walter, 1992); and
- South resource area: two historical analytical results in the North resource area (Moldovanyi and Walter, 1992) and eight analytical results from 2018 brine sampling programs conducted by Standard Lithium.

The sampling programs and the analytical results are discussed in detail in Section 6.2, Regional Assessment of the Lithium Potential of the Smackover Formation, and Section 9.2, 2018 Brine Sampling Programs.

To the best of the authors knowledge, the Middle Smackover Formation brine has not been sampled to determine its lithium content. The authors assume that because there is no evidence of a hydraulic barrier between the Upper and Middle Smackover formations, and the widespread nature of lithium-enrichment in the Smackover Formation in southern Arkansas (and in the high H_2S polygon of Moldovanyi and Walter (1992) that the brine composition of the Upper and Middle Smackover formations is similar.

14.3.3 Porosity and Permeability Data

Porosity and permeability data available to the authors included:

- Historical effective porosity measurements of more than 1,935 Smackover Formation core samples that yielded an average effective porosity of 14.3% (Manger, 1963);
- Historical permeability data that vary from <0.01 to >5,000 millidarcies (mD) with an average of 338 mD (Manger, 1963);
- 515 core plug samples from oil and gas wells within the Upper and Middle Smackover formations at the SWA Property were analysed for permeability and porosity and yielded an overall average permeability of 53.3 mD and a total porosity of 10.2%; and,
- 5,143 Smackover Formation total porosity values based on LAS density/porosity logs from 29 wells within, and/or adjacent to, the SWA Property that have an average total porosity of 9.2% (with negative total porosity values removed).

Sections 14.5.1 and 14.5.2 provide a detailed discussion of porosity and permeability for the SWA Property and surrounding area.

14.3.4 Data QA/QC

Roy Eccles P. Geol. conducted a site inspection of the SWA Property on March 5 to 9, 2018. The site visit validated the Property and observed active exploration at the Property in the form of using oil and gas infrastructure to obtain brine samples for analytical testing.

The well locations were vetted using aerial photos and survey plots (where required). The well logs were loaded into the Petra workstation and vetted to ensure that the proper logs were attached to the well. Three wells from IHS Markit were incorrect and fixed. Logs from other sources were vetted before being loaded into the workstation. Formation tops were made by Tom Wyche of Hill Geophysical Consulting in collaboration with Mr. Eccles. The picks were vetted by making grid maps and looking for outlier points. The few outliers that were found were corrected before importing the picks back into the working subsurface model.

Twenty-nine wells had density logs, which is representative of total porosity. These logs were digitized using Logscan software by Hill Geophysical Consulting staff, in collaboration with Mr. Eccles. Logscan allows digitization of raster log images. The raster image is placed in the background as the software traces the log's curve in automatic mode. The operator then corrects any errors using a manual picker. The density porosity logs from the study area were effective images and easy to digitize.

The seismic data were vetted upon loading into the Kingdom® software. This involved assigning shot point numbers, as seen on the paper prints, to the digital data traces once they were loaded. No problems were encountered.

The author has reviewed all geotechnical and geochemical data and the author of this section of the Technical Report has found no significant issues or inconsistencies that would cause one to question the validity of the wireline logs and seismic profiles used to make stratigraphic picks; core report porosity and permeability; and historical and current lithium-brine analytical results. Third-party geochemical laboratory reports, engineering core measurement reports, government information and/or publicly available well log information was generated using the proper procedures, has been accurately transcribed from the original source and is suitable for use in this Technical Report.

The authors did note an issue in converting the wireline density logs to total porosity, and therefore, do not use total porosity to determine the volume of brine within the Upper or Middle Smackover formations domain aquifer. As an alternative, the authors use the engineering core measurement reports and total porosity to quantify the average porosity of the Upper and Middle Smackover formations underlying the SWA Property. The reader is directed to additional discussion on total porosity involving the density logs in:

1. Section 14.5, Hydrogeological Characterization;
2. Section 14.6, Estimate of Average Porosity; and
3. Section 25.3 Risks and Uncertainties.

14.4 Step 1: Geometry and Volume of the Upper and Middle Smackover Formation Domains

14.4.1 Lateral Spatial Dimensions and Brine Ownership Within the Potentially Unitised Resource Area

The previous 2019 resource estimations were conducted using only the leases that are currently under agreement to Standard Lithium (see Section 4.1, Property Introduction). All areas that were not under lease by Standard Lithium were excluded from the 2019 resource estimation process and reporting. This exclusion of lands includes those 'islands' of leases that are not under TETRA/Standard Lithium ownership but occur within the generalized boundaries of the SWA Property.

Consequently, the 2019 mineral resources were estimated by applying a net acreage of 11,033 net mineral hectares (27,262 net mineral acres) together with an ownership percentage of between 73% and 79% under lease value for each section of Arkansas Public Land Survey System.

In this updated 2021 resource estimate, which supersedes and replaces the 2019 mineral resource, the author used a unitised area to calculate the resource. The unitised SWA Property encompasses 14,638 gross mineral hectares (36,172 gross mineral acres) and forms the updated resource area. In addition, the 2021 resource estimate applies a 100% brine ownership that is consistent with accessing all brine within the potentially unitised aquifer.

14.4.2 Stratigraphic Surface Modelling and Construction

The geographic land grid used to format and interpret the well data were from U.S. Geological Survey Topography using NAD27 Arkansas South 302 projection. The well data were loaded and interpreted in Petra™ geological interpretation software. Once all subsurface data were loaded and vetted, the author used best practice industry interpretation methods to depict the stratigraphic top and base of the Upper Smackover Formation domain and create contoured surface grid files for insertion into the 3D model.

Multiple cross-sections were generated in the study area to understand and define the key geological horizons (see Section 7.4, Property Geology: Characterization of the Smackover Formation) and the entire log was viewed/interpreted for each well. Shallow and deep horizons were picked, and geological correlations were straight forward for defining the top and bottom surfaces of the Upper and Middle Smackover formations.

The top of the Smackover Formation and the base of Upper Smackover Formation have distinct, sharp log changes that were consistently picked throughout the study area. The base of the Middle Smackover Formation has fewer well stratigraphic picks (n=19 wells) and is mapped using the electric log picks. Once the stratigraphic horizons in the logs were picked to the satisfaction of the loggers, grid maps were constructed to check the picks. Questionable picks were studied and fixed if needed.

The geological information (logs and formation 'top' and 'base' picks) was loaded into a Kingdom® software. As a complementary approach to mapping the Upper and Middle Smackover formations, the author used proprietary seismic data within the boundary of the SWA Property to support the regional dip of the reflectors and overall delineation of the top of the Upper Smackover

Formation domain. Converting seismic time values to depth values was accomplished using Kingdom's depth conversion routine. The well formation tops were contoured with the seismic data to establish velocity fields. The velocity fields in this area were simple due to the general nature of gentle regional dip.

The contouring of the linear (seismic) and random (well) data stratigraphic picks in Kingdom® resulted in a sufficient representation of the top of the Upper Smackover Formation. Some minor editing of the contours was made to reduce any 'spikes' in the surface grids (which were minimal).

With respect to structural features, the SW Property is directly north of a major fault system known as the State Line Fault Complex. In addition to the State Line Fault, a newly defined east-west-trending fault zone was discovered in the south-central part of the SWA Property during the modelling of the Smackover Formation and adjacent formations (see Section 9.1, Subsurface Data Review). The author conclude the SWA Property fault has some local modification of the strata, but in general, do not disrupt the Property-scale stratigraphic continuity and interpretation of the Smackover Formation.

Once the data were properly input, reviewed, and interpreted, the following surface contour files were generated:

1. The top of the Upper Smackover Formation as defined by log data from 104 wells and seismic data; and
2. The base of the Upper Smackover Formation (equivalent to the top of the Middle Smackover Formation) as defined by log data from 32 wells.

14.4.3 Three-Dimensional Modelling and Volume Calculation

APEX used the surface contour files representing the top and bottom surfaces of the Upper Smackover Formation at 3.1 m (10 foot) intervals (Figures 9-1 and 9-2) to construct a 3-D wireframe of the Upper Smackover Formation that is used to define the SWA Upper Smackover Formation aquifer domain in the North and South resource areas (Figures 14-2 and 14-3). The base of the Middle Smackover Formation was modelled at a continuous depth interval of 12 m (40 feet) below the top of the Middle Smackover Formation.

The Upper and Middle Smackover formations aquifer domains were clipped to the Property boundary and to the Lease boundaries and provides the starting point to evaluate the volume of the Upper and Middle Smackover formations domain aquifer underlying the SWA Property. Any non-lease areas, including those that are situated within the general boundary of the SWA Property, were removed from the resource areas and resource estimation process used in this Technical Report.

The spatial extent and vertical thicknesses of the Upper and Middle Smackover formations in the North and South SWA Property resource areas is summarized in Table 14-1. Pertinent unit thickness information includes the following:

- The Upper Smackover Formation occurs underneath the entire Property at depths of approximately -2,893 to -2,230 m below sea level (-9,491 to -7,317 feet).
- The average thickness of the Upper Smackover Formation is 50.8 and 47.7 m in the South and North resource areas, respectively.

- The Middle Smackover Formation aquifer occurs underneath the entire Property at depths of approximately -2,905 to -2,276 m below sea level (-9,531 to -7,277 feet).
- The average thickness of the Middle Smackover Formation was reasonably set based on the author's review of the unit at an assigned thickness of 12.2 m (40 ft) through the entire SWA Property area.

Figure 14-2. Orthogonal view of Property boundary (thick black line), drillhole collars (circles), drillhole traces (black lines), and interpreted Upper Smackover Formation (north - green solid, south – brown solid). The holes in the model show areas that are not under lease and have therefore been removed from the resource modelling and estimation process. Vertical exaggeration of 3:1.

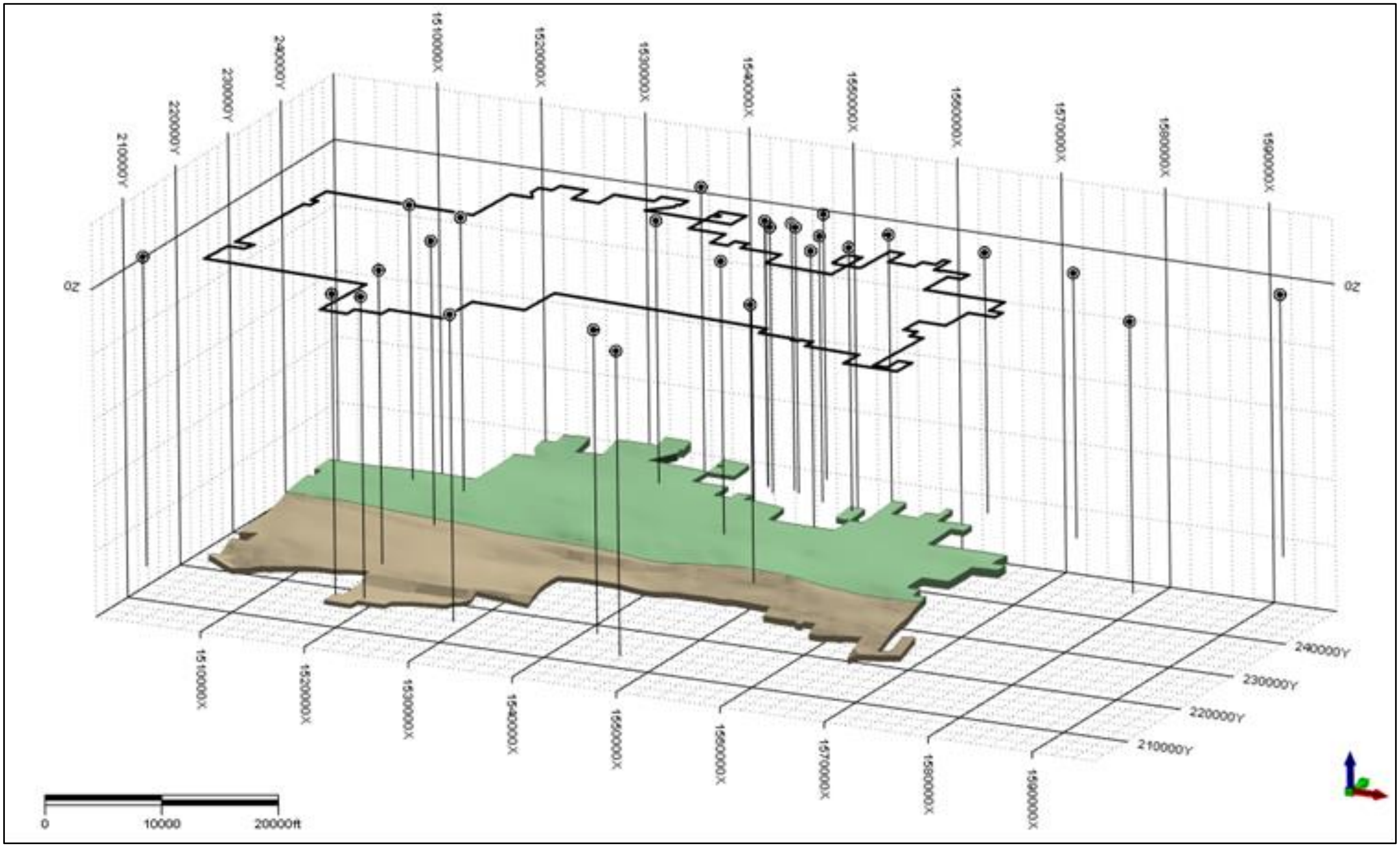
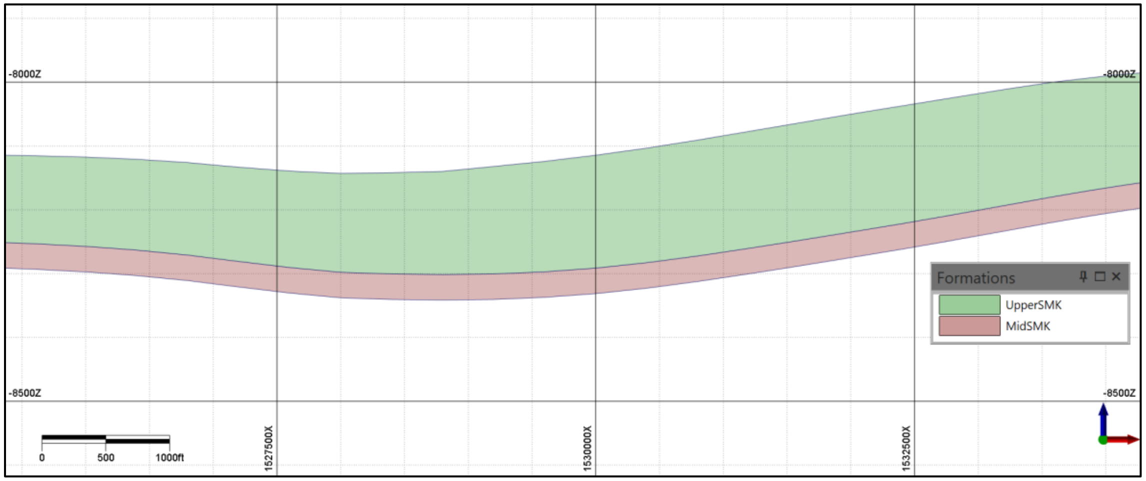
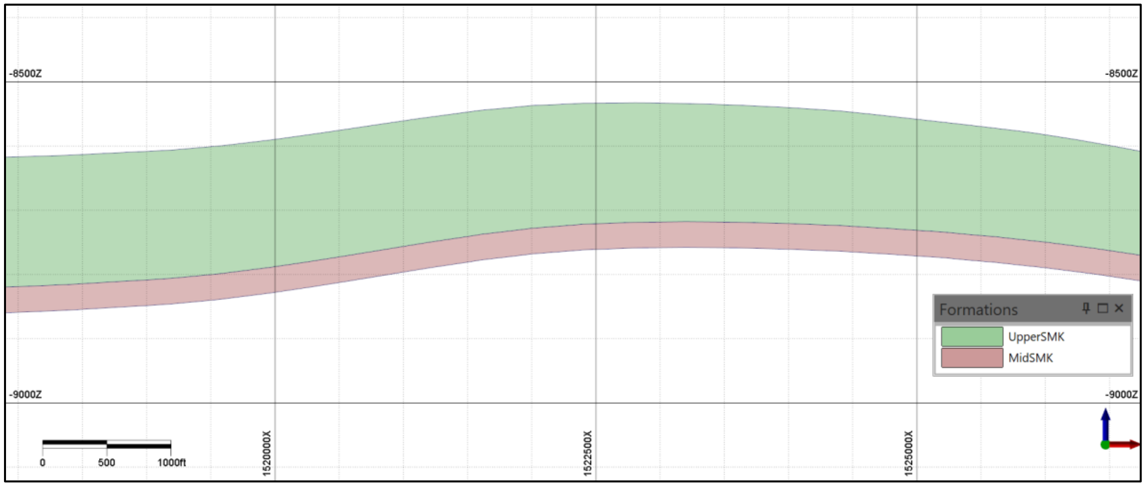


Figure 14-3. Cross-sections to show vertical extent of the Upper and Middle Smackover formations, in the North and South resource areas. Vertical exaggeration of 5:1

A) North resource area along 230000N looking north



B) South resource area along 220000N looking north



The spatial extent and vertical thicknesses of the Upper and Middle Smackover formations in the North and South SWA Property Resource areas is summarized in Table 14-1. Pertinent unit thickness information includes the following:

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- The average thickness of the Upper Smackover Formation is 50.8 and 47.7 m in the South and North resource areas, respectively.
- The Middle Smackover Formation aquifer occurs underneath the entire Property at depths of approximately -2,905 to -2,276 m below sea level (-9,531 to -7,277 feet).
- The average thickness of the Middle Smackover Formation was reasonably set based on the authors review of the unit at an assigned thickness of 12.2 m (40 ft) through the entire SWA Property area.

Table 14-1. Spatial extents of the resource areas and Upper and Middle Smackover Formations at the SWA Property.

	South Resource Area		North Resource Area	
	Upper Smackover	Middle Smackover [1]	Upper Smackover	Middle Smackover [1]
Area (km^2)	57.769	57.769	88.613	88.613
Thickness: SW corner (m)	47.3	12.192	60.0	12.2
Thickness: SEcorner (m)	46.9	12.192	61.0	12.2
Thickness: NE corner (m)	61.0	12.192	75.5	12.2
Thickness: NW corner (m)	60.0	12.192	43.3	12.2
Thickness: east-center (m)	60.9	12.192	49.8	12.2
Thickness: west-center (m)	62.0	12.192	43.6	12.2
Thickness: average (m)	50.8	12.192	47.7	12.2
Volume (km^3)	2.852	0.704	4.226	1.080

[1] The Middle Smackover had an assigned thickness of 12.2 m throughout the TETRA Property.

The author has investigated the stratigraphic continuity of the Upper and Middle Smackover formations in the 3D model. As per the quantitative summary in Table 14-1, the Smackover Formation rock units have generally uniform thicknesses throughout the Property but do decrease and dip sharply in thickness and orientation in the southernmost part of the Property. To explore this, we modelled the fault zones in their appropriate 3-D orientation such that the juxtaposition of Smackover Formation strata near the faults is correctly accounted for.

As a result, the author proposes that the thickness and dip of the southernmost Smackover Formation strata is being influenced locally by the Arkansas-Louisiana State Line Fault Complex, which occurs directly south of the Property and strikes in an east-west orientation (Figure 14-1).

While the influence of the State Line Fault on stratigraphy is evident, there is only minor stratigraphic variation observed in Smackover Formation strata near the central SWA Property fault zone (Figure 14-4). Despite the structural influence on the Smackover strata, Figure 14.4

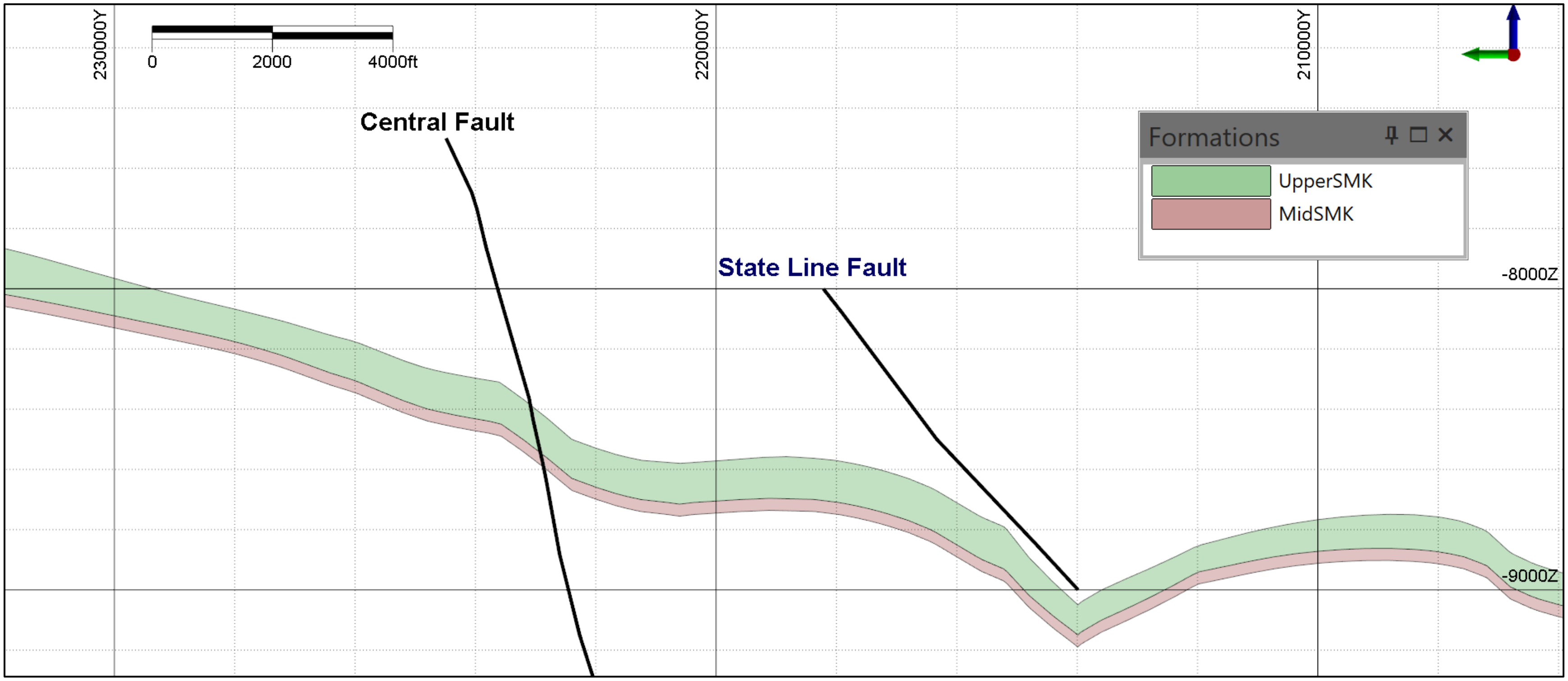
shows that the Upper and Middle Smackover formations strata are still continuous in all directions around the fault zones.

Accordingly, the authors conclude the State Line Fault does influence the proximal orientation and thickness of the Smackover Formation units, but the fault zones do not, in any way, separate the overall stratigraphic continuity of the strata at the SWA Property. We assume this would also apply to hydraulic interconnectivity of Upper and Middle Smackover formations domain aquifers, both horizontally and vertically, across the Property.

Based on this review of the subsurface stratigraphy and structural features within the 3D model, and conclusion of stratigraphic and aquifer continuity, the authors calculated the volumes of the Upper and Middle Smackover formations as they relate to the resource estimation reported in this Technical Report. The aquifer volumes of the four resource estimation areas include:

- North Upper Smackover aquifer volume = 4.226 km^3;
- North Middle Smackover aquifer volume = 1.080 km^3;
- South Upper Smackover aquifer volume = 2.852 km^3; and
- South Middle Smackover aquifer volume = 0.704 km^3 (Table 14.1).

Figure 14-4. Position of the State Line Fault Complex and its influence on the Upper Smackover Formation domain strata. Abbreviations: UpperSMK – Upper Smackover Formation; MidSmk – Middle Smackover Formation



14.5 Step 2 Hydrogeological Characterization of the Upper and Middle Smackover Formations

The Upper and Middle Smackover formations represent a large-scale confined aquifer that is bounded by two aquitards. The basal aquitard is defined by the Lower Smackover Formation, or Brown Dense, which underlies the Middle Smackover and Reynolds Members. The Lower Smackover Formation is composed of fine-grained lime mud (Section 7.3, Smackover Formation). Underlying the Brown Dense, basin-wide restriction resulted in deposition of a thick succession of the Louann Salt that covers much of the Gulf of Mexico region (Section 7.1, Gulf Coast Tectono-Depositional Framework).

Cross-formational fluid movement above the Smackover Formation is restricted by the overlying Buckner Formation, which consists of anhydrite and shale (Moore & Druckman, 1981; Vestal, 1950). The Buckner Formation acts as a top seal for hydrocarbons and brine (Parker, 1973). The oil, gas and brine are contained within the Upper and Middle Smackover formations creating a confined aquifer.

For this Technical Report two resource units, the Upper and Middle Smackover formations, have been identified. As discussed in Sections 7.4 (Property Geology: Characterization of the Smackover Formation) and 14.1 (Introduction), the justification to split into two adjoining units is based on: 1) by stratigraphic nomenclature and definition such that the two units can be distinguished in electronic log profiles (see Section 9.2); and 2) both formations exhibit uniquely representative porosities, which is not atypical of a Carbonate reservoir (Mazzullo and Chilingarian, 1992). However, based upon the porosities and permeabilities within the Upper and Middle Smackover formations act as one hydrogeologic unit. That is, there isn't a laterally continuously low permeability layer or confining unit that divides the hydrogeological parameters of the Upper Smackover Formation from the Middle Smackover Formation.

Because the Smackover Formation has been subject to decades of hydrocarbon and brine exploration, hydrogeological conditions are well documented in the public domain. The hydrogeological properties of the Upper and Middle Smackover formations are discussed in more detail in the following sections.

14.5.1 Porosity

Multiple sources of information were used to assess the porosity of the Upper and Middle Smackover formations, including: LAS density porosity logs; published Government, academic and journal literature; and independent laboratory analysis conducted on well cores from the SWA Property and surrounding area.

As discussed previously, the Smackover Formation has economic quantities of oil, gas and brine. Over the years, core samples have been collected and analysed for porosity and permeability to understand these properties. One extensive study by the United States Geological Survey (USGS) summarized more than 1,935 Smackover Formation core samples over southern Arkansas and analysed for porosity (Manger, 1963; Table 14-2).

The porosity of the more than 1,935 core samples from the Smackover Formation oil fields varied from 2% to 23.9% with an average of 14.3% (Table 14-2). According to the USGS study, porosity measured was either effective porosity or very likely to be effective porosity (these data are referred to as effective porosity in this Technical Report). Typically, effective porosity is calculated from the core laboratory analysis or through field testing. Effective porosity is an important parameter when assessing lithium-brine resources in a confined aquifer as it is a measure of the interconnectedness of pores through which the brine would flow to production wells.

The McKamie-Patton oil field is located on the southern portion of the SWA Property and included in the USGS study (Manger, 1963). The average effective porosity of the McKamie-Patton field from 1,767 core-plug samples was 14.2% (Manger, 1963; Table 14-2). Additionally, 14 core-plug samples from the same field had an average effective porosity of 7.5% (Manger, 1963). These effective porosities were enough to allow the economic extraction of oil from the Smackover Formation since the 1940s to present day.

Table 14-2. Summary of Smackover Formation porosity (from Manger,1963).

Location	Distance to Property (km and direction)	Approximate Depth (m)	Number of Samples	Minimum Effective Porosity (%)	Maximum Effective Porosity (%)	Average Effective Porosity (%)
Reynolds Unit, Cairo Field, Arkansas*	45 km East	≈2,377	NA	NA	NA	17
Reynolds Unit, Dorcheat Pool, Arkansas*	70 km East	2,749 - 2,771	NA	2	20	12
Reynolds Unit, Schuler Field, Arkansas*	45 km East	2,332 - 2,365	NA	NA	23	16.7
Reynolds Unit, Various Fields, Arkansas		2,210 - 2,332	4	16.4	20.0	18.0
Smackover Formation, Various Fields, Arkansas		≈2,393	150	0	23.9	14.5
Smackover Formation, McKamie-Patton pool, Arkansas*	On Property	≈2,835	1,767	NA	NA	14.2
Smackover Formation, McKamie-Patton pool, Arkansas	On Property	2,780 - 2,860	14	0	16.4	7.5
					Average Total	**14.3**

Notes

[1] NA denotes not available.

[2] * denotes very likely to be effective porosity.

Historically core samples were collected and analysed from wells drilled within the SWA Property. A summary of core analyses is provided in Table 14-3. Figure 14-5 shows the locations of the wells where core samples were analysed and used to assess the properties of the Smackover Formation. A total of 165.4 m (542.5 feet) of core has been collected and analysed mostly at 0.3 m (1 foot) intervals from 10 different wells. From these wells, 515 core plug samples from the Smackover Formation were analysed for porosity and permeability. The average effective porosity ranged from 0.7 to 31.0%. All within SWA Property Smackover Formation measurements combined yield an overall average effective porosity of 10.2%.

Of the 515 core plug measurements from the SWA Property, 219 measurements were from two wells (MKP#17 and MKP#19) located in the McKamie-Patton field. The core plug analyses for these wells were completed in 1954. The porosity measurements were likely included in the USGS study published in 1963 that identified the porosity measured from the McKamie-Patton field as very likely effective porosity (Manger, 1963).

Table 14-3. Summary porosity and permeability measurements conducted on historical core samples from wells located within the SWA Property area.

Well ID	Number of samples	Continuously cored interval (m)	Continuously cored interval (feet)	Porosity (%) Min.	Porosity (%) Max.	Porosity (%) Avg.	Permeability (mD) Min.	Permeability (mD) Max.	Permeability (mD) Avg.
Lester 1	34	13.1	43.0	1.2	17.4	5.1	0.0	43	2.6
Carter Moore 1	45	13.9	45.5	1.8	22.5	14.3	0.0	270	45.5
Lowery 1	47	9.0	29.5	0.7	14.0	5.5	0.0	1368	93.7
Cornelius 1	13	2.4	8.0	1.3	9.2	4.3	0.0	3.7	0.3
Vera Dixon 1	44	6.4	21.0	0.9	26.7	10.1	0.0	76	3.3
Neal Ellis 1	64	18.6	61.0	1.9	24.5	18.3	0.0	115	13.3
Big Six Oil Company	21	6.1	20.0	1.2	17.6	11.9	0.0	24.0	3.6
Fina McGoogan 1	28	10.5	34.5	1.4	14.6	6.7	0.0	259	15.2
MKP#17	113	41.8	137.0	4.0	31.0	13.0	0.0	2330	146.1
MKP#19	106	43.6	143.0	1.9	20.4	12.4	0.0	2590	209
Totals	**515**	**165.4**	**542.5**		**Averages**	**10.2**			**53.3**

As part of the 2018 exploration program, Standard Lithium reviewed core from the SWA Property stored at the Arkansas Geological Survey Core Laboratory in Little Rock, Arkansas (see Section 9.1.3 Core Report Analysis and Review.). Based upon the review of the core, Standard Lithium collected 18 select Smackover Formation core plugs and analysed the core for porosity and permeability to verify the historical results. A total of 15.1 m (49.5 feet) of core was analysed at select intervals from five different wells. The sample process simulated a grab-sampling approach and therefore is not representative of the collection of a continuous core sample.

The laboratory analytical results from Standard Lithium's core plug testing program is summarized in Table 14-4. The effective porosity ranged from 12.1% to 22.4% and have an overall average effective porosity of 17.8%.

As part of the historical compilation, core sample porosity measurements were reviewed from wells that directly surround the SWA Property. A summary of permeability and porosity data is presented in Table 14-5 and Figure 14-5. A total of 379 m (1243 feet) of core has been collected and analysed mostly at 0.3 m (1 foot) intervals from 22 different wells. From these wells, 1,110 core plug samples from the Smackover Formation were analysed for porosity and permeability. The average porosity ranged from 0.2 to 28.5%. All historical porosity measurements in the general area of the SWA Property yield a combined average effective porosity of 8.6%.

Of the 1,110 core plug measurements from the SWA Property area, 673 measurements were from six wells (MKP#2, MKP#4, MKP#7, MKP#8, MKP#10 and MKP#23) located in the McKamie-Patton field. The core plug analyses for these wells were completed between 1942 and 1956. The porosity measurements were likely included in the USGS study published in 1963 that identified the porosity measured from the McKamie-Patton field as very likely effective porosity (Manger, 1963; see Table 14.2).

Figure 14-5. Location of the core holes and corresponding well identifiers.

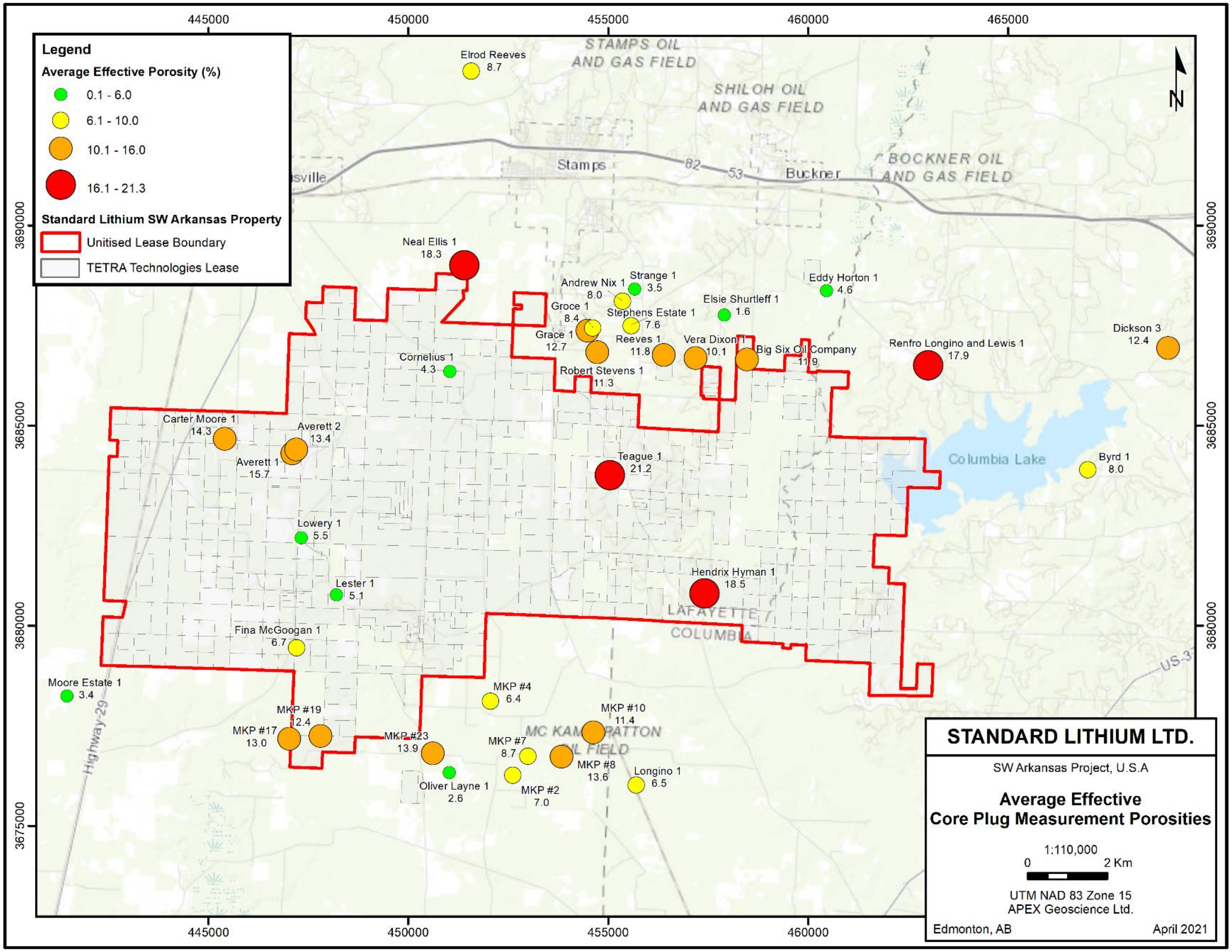


Table 14-4. Porosity and permeability measurements conducted by Standard Lithium core samples from select wells located on the SWA Property.

Well ID	Number of samples	Grab sample cored interval (m)	Grab sample cored interval (feet)	Porosity (%)			Permeability (mD)		
				Min.	Max.	Avg.	Min.	Max.	Avg.
Averret 1	8	10.1	33.0	13.1	19.2	15.7	2.8	505.0	196.0
Averret 2	3	1.5	5.0	12.1	14.5	13.4	299.0	712.0	524.7
Vera Dixon 1	1	0.2	0.5	20.3	20.3	20.3	1.6	1.6	1.6
Teague 1	3	1.4	4.5	20.0	22.4	21.2	91.0	488.0	229.7
Hendrix Hyman 1	3	2.0	6.5	15.3	20.4	18.5	146.0	1183.0	783.0
Totals	**18**	**15.1**	**49.5**		**Averages**	**17.8**			**347.0**

Table 14-5. Historical porosity and permeability measurements core samples near the SWA Property.

Well ID	Spatial reference to the TETRA Property	Number of samples	Continuously cored interval (m)	Continuously cored interval (feet)	Porosity (%)			Permeability (mD)		
					Min.	Max.	Avg.	Min.	Max.	Avg.
Elrod Reeves	North	34	5.0	16.5	1.8	15.7	8.7	0.0	173	33.5
Grace 1	North	8	2.1	7.0	2.9	19.5	12.7	0.0	412	133.1
Groce 1	North	61	6.1	20.0	1.7	22.3	8.4	0.0	168	30.4
Stephens Estate 1	North	16	4.4	14.5	3.8	10.8	7.6	0.0	4	0.3
Robert Stevens 1	North	15	4.0	13.0	3.6	18.8	11.3	0.0	250	55.6
Andrew Nix 1	North	36	5.5	18.0	1.3	15.7	8.0	0.0	90	6.2
Reeves 1	North	20	4.1	13.5	7.4	15.8	11.8	0.0	56	9.8
Strange 1	North	18	2.7	9.0	1.0	9.4	3.5	0.0	0	0.0
Elsie Shurtleff 1	North	5	3.7	12.0	0.7	2.7	1.6	0.0	0	0.0
Eddy Horton 1	North	42	7.9	26	0.2	11.3	4.6	0.0	111	3.0
Renfro Longino and Lewis 1	North	62	17.4	57	5.4	28.5	17.9	0.0	2,670	198.1
Byrd 1	East	8	13.7	45	2.5	16.4	8	0.0	675	126.9
Dickson 3	East	34	6.6	21.5	2.1	19.4	12.4	0.0	198	34.5
Moore Estate 1	South	70	10.5	34.5	0.8	12.8	3.4	0.0	4.08	0.3
Oliver Layne 1	South	5	1.2	4	1.4	6.1	2.6	0.0	0	0.0
Longino 1	South	3	0.6	2	3.9	11	6.5	0.8	37	13.5
MKP#2	South	101	30.5	100	1.2	19.3	7	0.0	30	1.4
MKP#4	South	136	41.8	137	1.5	16	6.4	0.0	1765	108.6
MKP#7	South	161	48.5	159.0	1.2	18.3	8.7	0.0	5980	227.7
MKP#8	South	69	67.1	220.0	1.9	23.1	13.6	0.0	2292	180.2
MKP#10	South	106	36.9	121.0	1.6	21.8	11.4	0.0	2730	113.5
MKP#23	South	100	58.8	193.0	4.4	26.8	13.9	0.0	997	144.1
	Totals	**1110**	**379.0**	**1243.5**		**Averages**	**8.6**			**64.6**

Within, or directly adjacent to the SWA Property, 29 wells contained LAS density porosity logs. These logs were digitized in stratigraphic sections including, and directly adjacent to the Upper and Middle Smackover formations. In total, there were 5,143 total porosity measurements that have an average total porosity of 9.2% when negative porosities were removed (Table 14-6).

To end, the reader is referred to Section 14.6 to review a statistical assessment of effective porosity that is used in the resource estimation. Total porosity from the LAS density logs were not used in the resource estimation (until a proper assessment of the negative values can be conducted and potentially rectified).

Table 14-6. Summary of the converted wireline density porosity dataset emphasizing the component of negative values and their influence on the average total porosity.

	All porosity data (including negative values)		A subset of the porosity data with all negative values removed	
	Porosity record count	**Average porosity**	**Porosity record count**	**Average porosity**
All total porosity measurements	5143	3.2	3194	9.2
Upper Smackover Fm. total porosity measurements	1975	-3.7	511	7.7
Middle Smackover Fm. total porosity measurements	518	4.8	365	9.5

14.5.2 Permeability

A summary of the published permeability values for the Smackover Formation in southern Arkansas is presented in Table 14-7. Historical published permeability values varied from 0.0 millidarcies (mD) to 5,520 mD with an average of 338 mD.

Fortunately, and specific to the SWA Property, historical permeability measurements were conducted on core plugs from the Smackover Formation from 10 wells presented in Table 14-3. Core plug permeability data includes measurements from the 515 samples that yielded values ranging from 0 to 2,590 mD with an average permeability of 53.3 mD (see Table 14-3).

In 2018, Standard Lithium completed permeability measurements from five wells located on the SWA Property (see Table 14-4 and Figure 14-5). Core plug permeability data from the 18 samples yielded values ranging from 1.6 to 1,183 mD with an average permeability of 347.0 mD.

Historical core sample permeability results were available from 22 wells located surrounding the SWA Property (Table 14-5 and Figure 14-5). The permeability ranged from 0.0 mD to 5,980 mD. The overall average permeability for wells surrounding the SWA Property was 64.6 mD.

Standard Lithium's core sampling program confirmed the historical results that high permeabilities are present on the SWA Property. Additionally, the permeabilities were confirmed to be variable within the Smackover Formation. To end, as discussed previously, these permeabilities were enough to allow the economic extraction of hydrocarbons from various fields within the Smackover Formation, particularly the Lewisville, Mars Hill, McKamie NE, McKamie-Patton, Mt Vernon and Kress City Fields that are present within the SWA Property.

Table 14-7. Summary of historical permeability values for the Smackover Formation. Reynolds Member is part of the Upper Smackover Formation.

	Permeability (mD)			
Formation Name (Field/Pool)	**Minimum**	**Maximum**	**Average**	**Source**
Reynolds Member	38	5520	1686	Fancher and Mackay (1946)
Smackover	/	/	100	Harris and Dodman (1987)
Upper Smackover (Mt. Vernon Field)	/	/	120	Harris and Dodman (1987)
Smackover	1	100	NA	Mancini et al. (2012)
Upper Smackover (Southern Zone)	< 0.01	100(?)	NA	Moore and Druckman (1981)
Smackover (Dolograinstones)	/	839	69.1	Prather (1992)
Smackover (Sucrosic Dolostones)	/	417	25.7	Prather (1992)
Smackover (Walker Creek Field)	0.1	>5000	30	Bliefnick and Kaldi (1996)
Smackover	1	100	/	Mancini et al. (2008)

14.5.3 Porosity-Permeability Observations

No direct statistical correlation between porosity and permeability exists in the Smackover Formation. However, if permeability is high, porosity is generally high. The same appears not to be true if the porosity is high. The highest porosity and permeability values are seen in the oölitic sections of the Smackover Formation (the Reynolds). Oömoldic intervals are usually lower permeability. There are both oölitic and oömoldic intervals with porosity reaching 10-15% with little to no permeability. Permeability often fluctuates greatly within an interval, exceeding 50 mD in a one-foot interval and dropping to almost zero in the next. Core intervals classified as 'probably brine productive' by the core report have permeability values exceeding 0.5mD.

Crystalline limestone (non-oölitic) has overall low porosity and permeability. Dolomite porosity and permeability varies, which can probably be attributed to it often being interlayered with limestone with varying thickness.

Regionally, oömoldic porosity occurs along the updip margins of the Smackover Formation and primary preserved porosity is found in downdip areas near the salt-basin margins (Moore, 1984).

14.5.4 Dispersivity

Hydrodynamic dispersion is a phenomenon of groundwater of different solute concentrations mixing through a process of molecular diffusion and mechanical dispersion (Fetter, 1988). Mechanical dispersion is a product of the flow velocity (rate of groundwater movement in the aquifer) and the dispersivity (a property of the aquifer). In a potential production scenario at the SWA Property, mixing would occur when injected tail-brine, free of lithium, combines with *in-situ* lithium containing brine in the Upper and Middle Smackover Formations. The reinjected lithium free brine would mix with brine containing lithium as described by a process of hydrodynamic dispersion.

As the Upper and Middle Smackover formations represents a permeable aquifer, the hydraulic head differences within the unit will result in fluid migration. Based upon the upper and lower layers that bound and restrict vertical flow within the Upper and Middle Smackover formations, most of the flow within the aquifer will be lateral (i.e., the upper and lower bounding surfaces include the overlying Buckner Formation anhydrite and underlying Brown Dense and/or Louann Salt). Hydrodynamic dispersion occurs within the conventional oil and gas production system but is not currently taking place with respect to lithium at the SWA Property.

During future operation of any lithium brine extraction plant, however, injected brine, free of Lithium, would mix with *in-situ* lithium-containing brine. In the case of the Upper and Middle Smackover formations, the large lateral extent and restricted vertical dimension, means the lithium mixing zone would vary laterally in the aquifer. Dispersivity will result in an increase of the length of the mixing zone along the aquifer as the lithium free brine finds velocity differences at the pore level within the flow system as well as different flow paths (highest velocities in the largest pore throats and lowest velocities near the grains).

Predicting the migration of brine with different lithium concentrations due to reinjected tail-brine, is beyond the scope of this Technical Report. It should be noted that dispersivities have been measured on the order of 10s of metres (Fetter, 1988). Based upon brine extraction and reinjection volumes that may be associated with potential brine production at the SWA Property, dispersivity variations of 10s of metres is not an important brine concentration variability factor within the Upper and Middle Smackover formations. That is, the lateral difference between the injected tail-brine and *in-situ* brine will likely be on the order of 10s of meters due to dispersivity alone.

14.5.5 Anisotropy

An assessment was completed of the Upper Smackover Formation (Reynolds Member) anisotropy or the hydraulic properties varying by direction (horizontal versus vertical). A review of published literature indicated the average Upper Smackover Formation horizontal and vertical permeabilities were reported to be 675 mD and 650 mD, respectively, for the McKamie-Patton Field (Shreveport Geological Society, 1945). Two wells (MKP#8 and MKP#23) measured both horizontal and vertical permeability from selected core plugs (Table 14-8). The average horizontal and vertical permeabilities from a total of 51 samples were 285.9 mD and 212.6 mD, respectively.

Therefore, the horizontal permeability is slightly higher than the vertical permeability based upon the literature information and core analysis in the immediate vicinity of the SWA Property. A slightly higher horizontal permeability would result in more horizontal flow of brine to production wells; however, the vertical movement of brine would also be occurring due to the small difference in horizontal and vertical permeability.

Table 14-8. Summary of horizontal and vertical permeability measurements from the SWA Property and surrounding area

					Permeability (mD)					
					Horizontal			Vertical		
Well ID	Spatial reference to the TETRA Property	Number of samples	Continuously cored interval (m)	Continuously cored interval (feet)	Min.	Max.	Avg.	Min.	Max.	Avg.
MKP#8	South	21	34.4	113.0	1.0	2292.0	387.0	1.0	1419	273.0
MKP#23	South	30	42.1	138.0	1.0	875.0	184.8	0.0	501	152.2
	Totals	**51**	**76.5**	**251.0**		**Averages**	**285.9**			**212.6**

14.5.6 Groundwater Levels in the Smackover Formation

Fluid levels at wells MKP#20 and MKP#21 were measured during Standard Lithium's 2018 exploration program and the collection of brine samples for lithium analysis. The method of fluid level measurement consisted of lowering the swabbing equipment into the production tubing and detecting a change in the rate of descent thus indicating the formation water +/- oil fluid level. The depth to the fluid was then recorded. The fluid levels were measured at wells MKP#20 and MKP#21 were 1,829 and 1,585 m (6,000 and 5,200 feet) below ground surface, respectively.

It should be noted that wells MKP#20 and MKP#21 were not operational at the time of sampling and are currently shut in. (i.e., they were re-opened for the sole intent of sampling the brine by Standard Lithium).

For comparative purposes we have compiled reservoir data for the Smackover Formation from nearby fields in southern Arkansas. These data are the 'original' reservoir pressure obtained between 1933 to 1943 (Fancher and MacKay, 1946). The average calculated groundwater depth was 326 m (1,070 feet) below the ground surface, assuming a water density of 1.2 g/mL (Table 14.9). The original reservoir groundwater depth in the McKamie-Patton Field was calculated to be 284 m (932 feet) below ground surface.

Therefore, with the extraction of hydrocarbons, gas and brine from the McKamie-Patton Field since 1940s the reservoir groundwater level has been lowered by approximately 1,423 m (4,668 feet). In the area of wells MKP#20 and MKP#21 the top of the Smackover Formation is about 2,743 m (9,000 feet) below ground level. Thus, the groundwater level is approximately 1,036 m (3,400 feet) above the top of the Smackover Formation and confirms the aquifer is a confined aquifer.

Table 14-9. Original reservoir data from Smackover Formation oilfields in southern Arkansas (from Francher and MacKay, 1946)

Field name	Reservoir pressure	Elevation OWC contact	P/D Ratio	Assumed ground elevation (feet)	Head Metres	Calculated water depth (m)
Atlanta	3821	-8000	0.46	256	-200.39	278
Big Creek	3733	-7731	0.46	361	-169.95	280
Buckner	3195	-7010	0.44	292	-265.30	354
Calhoun	3450	-8006	0.42	138	-419.52	462
Columbia	3750	-7817	0.46	256	-186.20	264
Magnolia	3465	-7293	0.45	341	-193.41	297
Mckamie Patton	4365	-9042	0.47	279	-199.37	284
Midway	2920	-6225	0.41	889	-187.10	458
Mt. Holly	3180	-6943	0.44	272	-253.66	337
Shuler	3550	-7420	0.46	249	-182.34	258
Texarkana	3296	-7062	0.44	364	-221.99	333
Village	3350	-7123	0.45	302	-208.96	301
Average	**3506**		**0.45**			**326**

Note:

Reservoir pressure in pounds per square inch.

14.5.7 Specific Storage and Storativity

As the Upper and Middle Smackover formations are a confined aquifer, the specific storage was estimated based on the compressibility of water and the compressibility of the aquifer. The relationship between specific storage (S_s) and compressibility is described by Kruseman and de Ridder (1994) as follows:

$$S_s = \rho_w \, g \, (\alpha + n \, \beta)$$

Where:

ρ_w = density of the brine (M/L^3);

g = acceleration due to gravity ($Force/L^3$);

α= compressibility of aquifer skeleton ($L^2/Force$);

n = porosity; and

β = compressibility of the brine ($L^2/Force$).

Based on the overall porosity of 10.0%, brine density of 1.200 g/cm^3 (see Sections 9.1 and 9.3, 2018 Brine Sampling Program), aquifer compressibility of 2.63 x 10^{-11} m^2/N, and brine compressibility of 6.59 x 10^{-11} m^2/N (Earlougher, 1977), the specific storage of the Upper and Middle Smackover formations is estimated to be 3.87 x 10^{-7} m^{-1}.

Due to the relatively low compressibility of the Upper and Middle Smackover formations, the calculated specific storage is at the lower end of typical aquifer materials as shown in Table 4.10.

Table 14-10. Representative values of specific storage for various geological materials (from Domenico and Mifflin, 1965; and Batu, 1998).

Material	Specific storage (ft^{-1})
Plastic clay	$7.8x10^{-4}$ to $6.2x10^{-3}$
Stiff clay	$3.9x10^{-4}$ to $7.8x10^{-4}$
Medium hard clay	$2.8x10^{-4}$ to $3.9x10^{-4}$
Loose sand	$1.5x10^{-4}$ to $3.1x10^{-4}$
Dense sand	$3.9x10^{-5}$ to $6.2x10^{-5}$
Dense sandy gravel	$1.5x10^{-5}$ to $3.1x10^{-5}$
Rock, fissured	$1.0x10^{-6}$ to $2.1x10^{-5}$
Rock, sound	$<1.0x10^{-6}$

Storativity (S) of the aquifer was determined by multiplying the average aquifer thickness (Section 14.3) by the specific storage. Using an average combined Upper and Middle Smackover formations thickness of 61.5 m (202 ft; see Table 14.1) the storativity (dimensionless) of the aquifer is 2.4×10^{-5}.

14.5.8 Hydraulic Conductivity and Transmissivity

Hydraulic conductivity of the aquifer was calculated from the permeability measurements of the Upper and Middle Smackover formations core analysis on the property and the physical properties of the brine (density of 1,200 kg/m^3). The relationship between hydraulic conductivity (K) and permeability is described by Fetter (1988) as follows:

$$K = K_i (\rho_w g / \mu)$$

Where:

K_i = permeability of the aquifer (L^2);

ρ_w = density of the brine (M/L^3);

g = acceleration due to gravity (L/T^2); and

μ = dynamic viscosity of the brine (M/(T L)).

The dynamic viscosity of the brine is 1.4 centipoise at a temperature of 70ºC and density of 1,200 kg/m^3 (Cabot Corporation, 2014).

The maximum hydraulic conductivity measured from the core on the SWA Property was 2.1×10^{-5} m/s. The average hydraulic conductivity on the SWA Property from the analysis of 515 core samples was 4.4×10^{-7} m/s. The average hydraulic conductivity is typical of limestone (Freeze and Cherry, 1979).

Transmissivity of the aquifer was determined by multiplying the average aquifer thickness by the average hydraulic conductivity of the Property. Using an average Upper and Middle Smackover formations thickness of 61.5 m (202 feet) the average transmissivity of the aquifer is 2.7×10^{-5} m^2/s.

14.5.9 Summary of Hydrogeological Conditions

The aquifer associated with the Upper and Middle Smackover formations is a confined aquifer situated between upper- and lower-bounding aquitards. The brine levels within wells operated by Mission Creek are about 1,036 m (3,400 feet) above the top of the Smackover Formation based on Standard Lithium's 2018 brine sampling program and discussions with Mission Creek (Mr. J. Young, pers. comm., 2018).

The occurrence of reservoir-grade rocks (porosity and permeability of at least 6% and 0.1 mD) in the Smackover Formation is dependent on: 1) deposition of porous and permeable sediments in a variety of settings; and 2) diagenetic processes that have preserved, enhanced, or created porosity and permeability both in originally permeable strata and in originally impermeable or poorly permeable strata (Kopaska-Merkel et al., 1992).

The average effective porosity and permeability at the SWA Property is 10.2% and 53.3 mD, respectively (Table 14.3). Using an average combined Upper and Middle Smackover formations thickness of 61.5 m (202 feet) the:

- hydraulic conductivity of the aquifer is 4.4×10^{-7} m/s;
- transmissivity of the aquifer is 2.7×10^{-5} m^2/s; and
- storativity of the aquifer is 2.4×10^{-5}.

These aquifer characteristics were collected from wells located in the oilfields that have or are currently operating on the SWA Property.

It is the opinion of the author of this Section that the Upper and Middle Smackover formations (aquifers) at the SWA Property appear to have reservoir and hydrogeologic properties that demonstrate and meet the criteria for reasonable prospectivity for economic extraction. This supposition is supported by the author who ties this hydrogeological conclusion together with other points and/or assumptions to further demonstrate the prospect for economic extraction of lithium-brine at the SWA Property in Section 14.7.4, Evaluation of Reasonable Prospects for Economic Extraction.

14.6 Step 3: Estimate of Average Porosity in the Upper and Middle Smackover Formations Domain Aquifers

In this sub-section, the authors assess the effective porosity data (core plug measurements) toward defining the total amount of *in-situ* brine within the Upper and Middle Smackover formations domain aquifers within the North and South resource areas. We assessed 1,474 effective measurements from 33 wells, 28 of which (n=776 measurements) were representative of the Upper and Middle Smackover formations.

Of the 33 wells, 10 were located within the boundary of the SWA Property and the other 23 wells occur at a maximum horizontal distance of approximately 7,000 m (23,000 feet) from the Property boundary. All core plug samples were located within the interpreted Upper and Middle Smackover formations domain aquifer described in Section 14.5.1 (Porosity). The following subsections describe the processing of the data to ensure the calculated effective porosity values are representative and appropriate for use in the resource calculation. Summary statistics of the un-capped and clustered core porosity measurements are detailed in Table 14.11.

Table 14-11. Summary statistics of un-capped and clustered core porosity measurements for the Upper and Middle Smackover formations.

	Upper Smackover	Middle Smackover
count	368	408
mean	10.304	11.312
standard deviation	5.891	7.253
variance	34.701	52.613
coefficient of variation	0.572	0.641
minimum value	0.200	0.500
25th percentile	5.100	3.775
50th percentile	10.300	12.200
75th percentile	14.125	17.300
maximum value	26.700	31.000

Note: The total porosity from the wireline density logs from 29 wells (n=5,143 total porosity values) was not used to assess the average porosity because there is not enough compatible data between the effective and total porosity datasets to make meaningful comparisons, and therefore, the authors do not have the confidence level to:

1) Use the total porosity data from the density logs to develop a block model of the SWA Property Smackover Formation to estimate the total in-situ brine within the aquifer; or
2) Depict the average porosity of the SWA Property Smackover Formation based on the total porosity data from the density logs.

14.6.1 Declustering

It is typical to collect data in a manner that preferentially samples low or high valued areas. This is acceptable practice; however, it produces closely spaced measurements that are likely statistically redundant. In this case, a simple average of all measurements that does not consider the closeness of data produces a spatially biased (i.e., clustered) value that does not adequately represent the overall volume of interest. It is therefore desirable to have spatially representative (i.e., declustered) statistics for global resource assessment and to check estimated models.

Cell declustering calculates a weight for each datum used to calculate declustered summary statistics and distributions that are spatially representative of the volume of interest, such as a declustered mean. The calculated weights for data that are close are lower, while data that are far apart are higher. Cell declustering was performed for core plug porosity measurements from the Upper and Middle Smackover formations.

14.6.2 Capping

To ensure porosity is not overestimated, outlier values that appear higher than expected, relative to the global population, are replaced with a maximum cap value. Extreme outlier values are valid measurements; however, their spatial continuity is limited compared to the global population, and without treatment, they unreasonably influence the calculated average value.

A probability plot illustrating all raw porosity measurements is used to identify outlier values. Figures 14.6 and 14.7 illustrate a probability plot for core porosity measurements from the Upper and Middle Smackover formations, respectively. In the Figures, the global population is represented by dense black points while outliers that breakaway at the high end of the distribution are coloured red. The probability plot of raw porosity values within the Upper and Middle Smackover (Figures 14.6 and 14.7) formations suggests there are four outlier measurements from the Upper Smackover and six outlier measurements from the Middle Smackover Formation greater than 24 %.

Hence, a capping level of 24% was applied to raw porosity measures used to calculate the average effective porosity value. The resulting capped and declustered histogram distributions of the core porosity measurements from the Upper and Middle Smackover formations are illustrated in Figures 14.8 and 14.9, respectively. Summary statistics of the capped and declustered core porosity measurements are detailed in Table 14.12. The distribution of porosity measurements in the Upper and Middle Smackover formations is shown on Figure 14.10.

Figure 14-6. Probability plot of porosity measurements within the Upper Smackover Formation before capping. The global population and outlier values that are capped are designated by black and red dots, respectively.

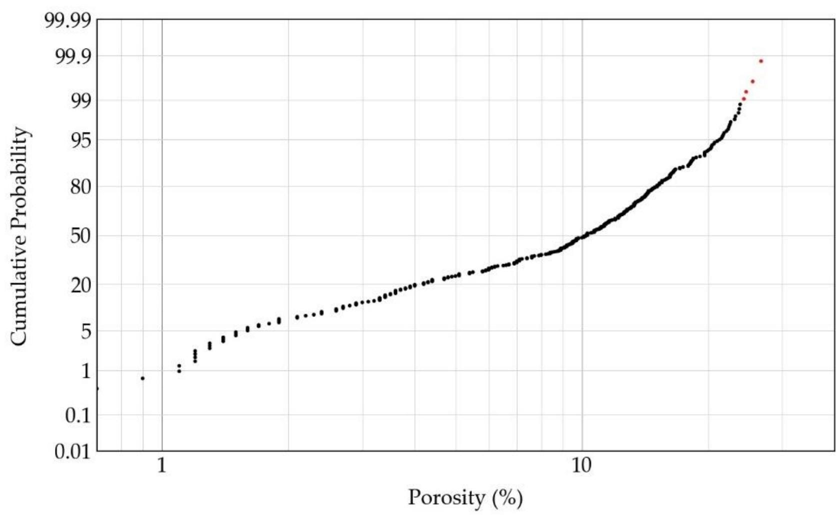


Figure 14-7 Probability plot of porosity measurements within the Middle Smackover Formation before capping. The global population and outlier values that are capped are designated by black and red dots, respectively.

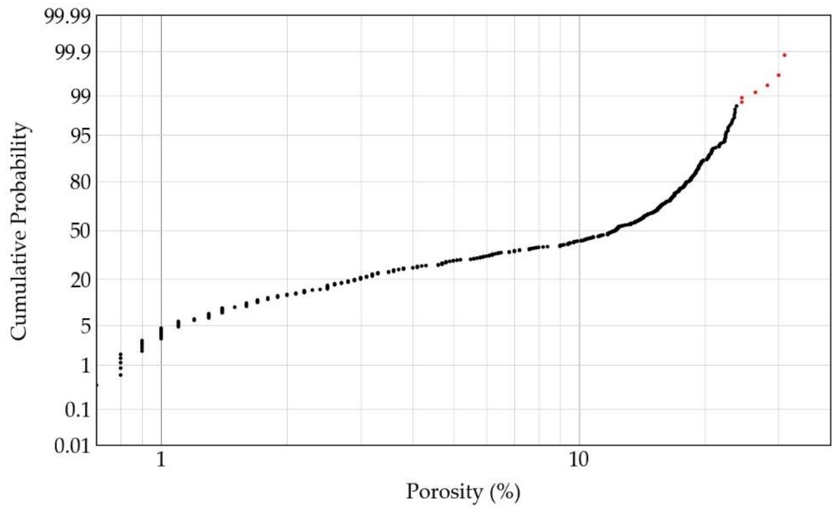


Figure 14-8. Histogram of capped porosity measurements within the Upper Smackover Formation. Abbreviations: n – number of observations; m – mean; σ – standard deviation; CV – Coefficient of variation; x_{max} – Maximum value; x_{75} to x_{25} – 75th to 25th percentile; x_{min} – minimum value

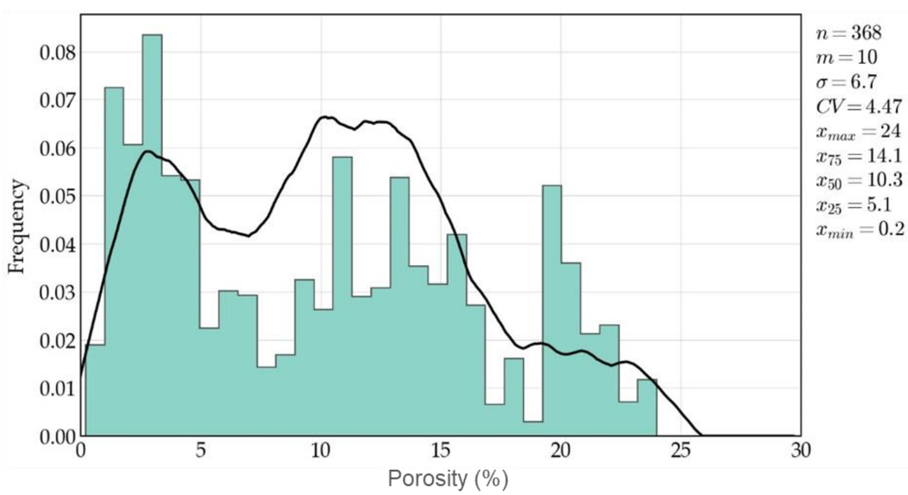


Figure 14-9. Histogram of capped porosity measurements within the Middle Smackover Formation. Abbreviations: n – number of observations; m – mean; σ – standard deviation; CV – Coefficient of variation; x_{max} – Maximum value; x_{75} to x_{25} – 75th to 25th percentile; x_{min} – minimum value

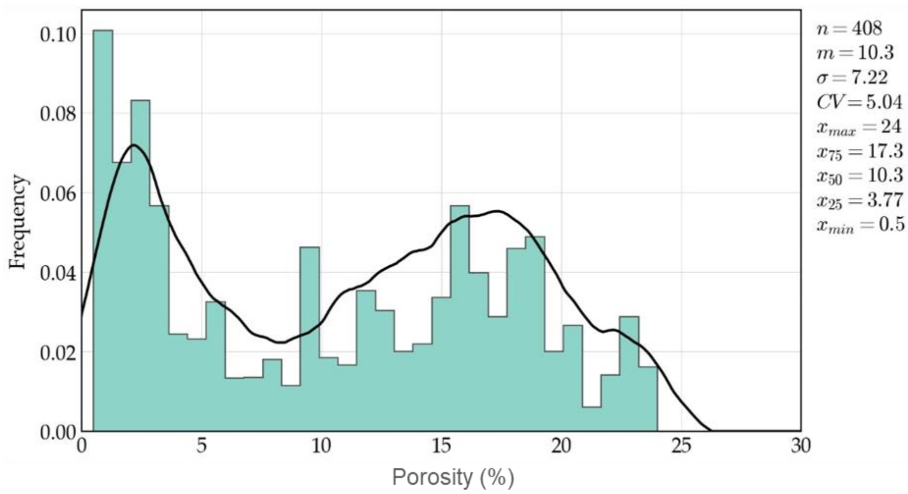


Table 14-12. Summary statistics of capped and declustered core porosity measurements for the Upper and Middle Smackover Formations.

	Upper Smackover	Middle Smackover
count	368	408
mean	10.045	10.343
standard deviation	5.856	7.145
variance	44.889	52.107
coefficient of variation	0.583	0.691
minimum value	0.2	0.5
25th percentile	5.1	3.775
50th percentile	10.3	12.2
75th percentile	14.125	17.3
maximum value	24	24

14.7 Step 4: Pore Space Brine Availability

Brine within the SWA Property is currently being pumped from the subsurface Smackover Formation as a waste by-product of oil and gas production. Consequently, the modal abundance of hydrocarbon and brine must be considered as a component of a resource estimation that is interdependent (at least temporarily) on petro-production.

The authors assume 98% of the pore space in the Smackover Formation contains brine. This assumption includes both Upper and Middle Smackover Formations and is based on:

1. Personal communication with oil and gas companies in the area (e.g., John Young, Mission Creek Opco LLC, pers. comm., 2018);

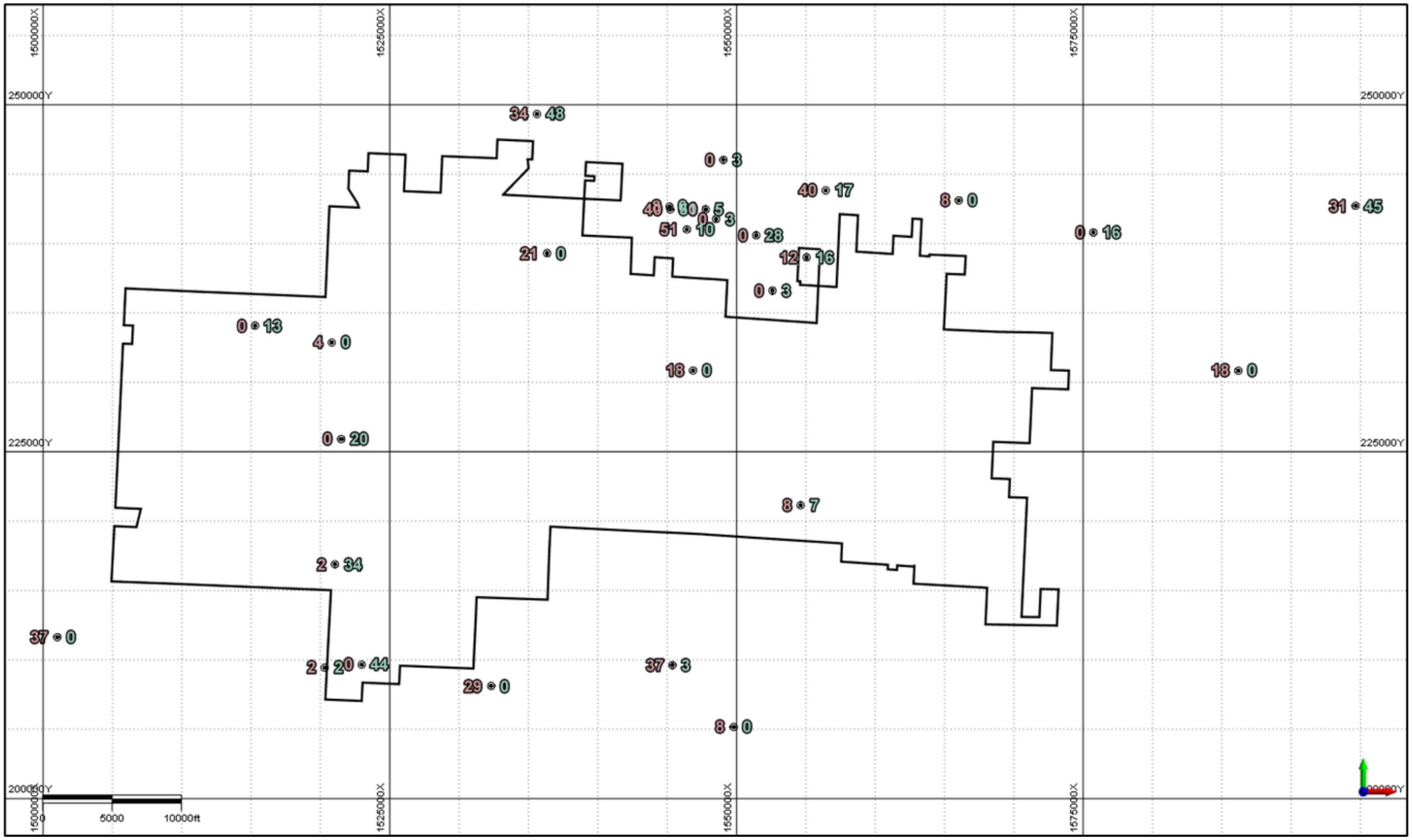
2. On personal observation of the Smackover Formation brine-oil ratio by the author;

3. Smackover Formation oil reservoirs being limited to structural highs with the assumption that only the uppermost portion of the Smackover Formation reservoir contains production-worthy oil; and

4. The observation that known oil reservoirs account for less than a roughly estimated 15% of the surface area at the SWA Property, and hence, the remaining non-oil productive portions of the Smackover Formation should, in theory, be dominated by brine.

Aquifer and reservoir conditions underlying the SWA Property, therefore, support a high brine to oil ratio in the Smackover Formation.

Figure 14-10. Spatial location of wells with core-plug effective porosity measurements. The number of porosity measurements from core plug samples from each well are provide beside the well collar (Upper Smackover Formation values on the right, Middle Smackover Formation values on the left).



14.8 Step 5: Lithium-Brine Concentration

The reader is referred to Section 6, History and Section 9.2, 2018 Brine Sampling Program for a complete discussion on lithium-brine geochemical results at the SWA Property. Standard Lithium WetLab results were chosen based on analytical results of the semi-certified standard sample spikes (see Section 11.5.2, Semi-Certified Standard Sample Comparison).

The average lithium-in-brine concentration used in the resource estimations presented in this Technical Report are:

- 160 mg/L lithium for the North resource area defined by two historically published analytical results (from Moldovanyi and Walter (1992); and

- 399 mg/L lithium for the South resource area defined by using two historically published analytical results (from Moldovanyi and Walter (1992) together with WetLab analytical results from 4 analytical results obtained from 2018 brine sampling conducted by Standard Lithium (Table 14.13).

14.9 Mineral Resource Estimate

14.9.1 Definition of Mineral Resource

The updated SWA Property inferred Lithium-brine resource estimate has been classified in accordance with guidelines established by the CIM "Estimation of Mineral Resources and Mineral Reserves Best Practice Guidelines" dated November 29th, 2019, and the CIM "Definition Standards for Mineral Resources and Mineral Reserves" amended and adopted May 10th, 2014. By definition,

"An Inferred Mineral Resource is that part of a Mineral Resource for which quantity and grade or quality are estimated on the basis of limited geological evidence and sampling. Geological evidence is sufficient to imply but not verify geological and grade or quality continuity".

14.9.2 Resource Classification Methodology

APEX has classified the SWA Property lithium-brine resources as an Inferred Mineral Resource. The SWA Property is an early-stage exploration project and there has limited geological sampling and the geological evidence is sufficient to imply but not verify geological grade or quality continuity.

Table 14-13. Summary of 2018 geochemical Lithium data at the SWA Property.

A) North TETRA

Well ID	Latitude	Longitude	Dominion Land System	Total well depth (m)	Well status	Lab	Li (mg/L)	Br (mg/L)	B (mg/L)	Na (mg/L)	K (mg/L)	Ca (mg/L)	Mg (mg/L)	Sr (mg/L)	Cl (mg/L)	TDS (mg/L)	Source
Haberyan 1	33.29596	-93.55113	2-17S-24W	2,580	P&A	na	187	6,856	155	75,625	2,928	43,275	4,538	2,949	204,588	341,953	M&W, 1992
Purser 2	33.29984	-93.55113	2-17S-24W	2,580	P&A	na	132	5,746	137	62,500	2,285	37,100	3,798	2,483	173,532	288,472	M&W, 1992
						Average	**160**										

B) South TETRA

Well ID	Latitude	Longitude	Dominion Land System	Total well depth (m)	Well status	Lab	Li (mg/L)	Br (mg/L)	B (mg/L)	Na (mg/L)	K (mg/L)	Ca (mg/L)	Mg (mg/L)	Sr (mg/L)	Cl (mg/L)	TDS (mg/L)	Source
Cornelius 1	na	na	23-17S-24W	2,747	P&A	na	423	4,276	358	72,500	7,100	29,300	2,243	2,258	176,679	296,891	M&W, 1992
Cornelius 2	na	na	23-17S-24W	2,756	P&A	na	370	3,752	319	63,525	6,150	25,450	1,902	1,964	155,618	260,593	M&W, 1992
MKP-20-1B	33.23241	-93.55148	35-17S-24W	2,885	Prod.	WetLAB	347	5,940	260	91,600	6,760	37,700	2,340	2,900	212,000	293,000	Standard Lithium, 2018
MKP-20-1B	33.23241	-93.55148	35-17S-24W	2,885	Prod.	WetLAB	352	/	255	74,500	5,140	39,400	2,400	2,720	200,000	322,000	Standard Lithium, 2018
MKP-20-1	33.23241	-93.55148	35-17S-24W	2,885	Prod.	ALS-H	265	4,680	298	59,100	4,090	29,400	2,230	2,050	213,000	365,000	Standard Lithium, 2018
MKP-20-1B	33.23241	-93.55148	35-17S-24W	2,885	Prod.	ALS-H	302	/	bld	63,100	4,560	36,200	2,650	2,660	/	369,000	Standard Lithium, 2018
MKP-21	33.22617	-93.56029	35-17S-24W	2,860	Prod.	WetLAB	461	6,400	325	66,700	6,800	38,100	2,560	3,010	210,000	348,000	Standard Lithium, 2018
MKP-48 (dup of MKP-21)	33.22617	-93.56029	35-17S-24W	2,860	Prod.	WetLAB	439	6,360	322	56,800	6,450	39,300	2,620	3,070	208,000	391,000	Standard Lithium, 2018
MKP-21	33.22617	-93.56029	35-17S-24W	2,860	Prod.	ALS-H	380	4,750	310	52,200	5,940	28,500	2,840	1,790	210,000	368,000	Standard Lithium, 2018
MKP-48 (dup of MKP-21)	33.22617	-93.56029	35-17S-24W	2,860	Prod.	ALS-H	425	4,960	342	59,600	6,370	32,900	3,030	2,300	221,000	377,000	Standard Lithium, 2018
						Average	**399**										

M&W, 1992 - Moldovany and Walter (1992)
P&A - Well is plugged and abandoned
Prod. - Well is currently producing oil
bld - Below the limit of detection
/ - Analysis not completed
na - Information not available
Historical and 2018 primary-lab (WetLAB) analytical data used to define the average lithium concentration used in the resource estimation. Note: ALS-H was used as a check-lab.

14.9.3 Market Conditions and Pricing

See Section 19 for an in-depth analysis of future lithium chemical pricing.

14.9.4 Step 6: Evaluation of Reasonable Prospects for Economic Extraction

A Mineral Resource is a concentration or occurrence of a material of economic interest in or on the Earth's crust in such form, grade or quality and quantity that there are reasonable prospects for eventual economic extraction. Evaluation of the SWA Property and lithium-brine information associated with the updated SWA inferred lithium-brine resource estimate has demonstrated and defined prospects for economic extraction. To support this contention, the reasonable prospect for economic extraction is supported by the following points and/or assumptions:

- Property geometry: The unitisation of the SWA Property would provide the most efficient pathway for the production process by protecting the production rights of the brine operator and the correlative rights of mineral interest owners (R.C. Lawson, personal communication, 2021).
- Aquifer geometry: The subsurface well data review shows that the target stratigraphic horizons, the Upper and Middle Smackover formations, are laterally continuous and underlie the entire SWA Property.
- Hydrogeological characterization: The Smackover Formation aquifer represents a large-scale aquifer that is bound above and below by two aquitards. The average effective porosity and permeability on the SWA Property is 10.2 % and 53.3 mD, respectively. The average hydraulic conductivity is 4.4 x 10^{-7} m/s, transmissivity is 2.7 x 10^{-5} m^2/s and storativity of the aquifer is 2.4 x 10^{-5}.
- Brine access: Standard Lithium has signed an agreement with TETRA to access the brine, with an overarching goal to develop commercial extraction of lithium from brine beneath the SWA Property.
- Brine volume and flow rate: Over the last five years (2013 to 2017) six Smackover Formation production wells have produced approximately 687 m^3 of brine as a waste product of oil and gas exploration and production.
- Brine grade: The average lithium concentration of the brine underlying the North and South resource areas is 160 mg/L Li and 399 mg/L, respectively.
- Recoverability: Standard Lithium has successfully completed the conversion of its Arkansas-produced lithium chloride into 99.985% pure lithium carbonate using OEM technology. The work was completed by Veolia Water Technologies (Veolia) at their facility in Plainfield, Illinois, and demonstrates that the lithium chloride intermediate product produced by Standard Lithium's industrial scale LiSTR DLE Demonstration Plant in Arkansas can be converted into better-than battery quality lithium carbonate using established OEM carbonation technology (Standard Lithium Ltd., 2021).
- Product value: Lithium-brine demand is anticipated to increase due to its large potential resource(s), longer life, lower operating cost and higher margins (Salier, 2018). As global demand for lithium increases, production technology has evolved to reduce the processing time of lithium from brine. The resulting technology invites the opportunity to consider lithium production from lower concentration, but large source, confined aquifer brine deposits.

This lithium-brine Technical Report has been prepared by a multi-disciplinary team of QPs that include geologists, hydrogeologists, and chemical engineers with relevant experience in the Smackover Formation brine geology and brine processing.

14.9.5 Cutoff

Numerous examples of lithium cutoff values for resource estimation are available in the public domain for continental brine deposits (i.e., unconfined or surficial salar deposit models; e.g., Spanjers, 2015; Reidel, 2017; Rosko, 2017; Burga et al., 2018). To the best of the author's knowledge, however, there are no analogous lithium-based cutoff values for subsurface, confined, aquifer-hosted lithium-brine.

Rather, other authors have assigned atypical cutoff definitions for this type of lithium-brine deposit such as "Production Factor" to the resource estimate (e.g., MacMillan and Binks, 2018), or have avoided a lithium cutoff (in favour of an *in-situ* estimate) due to the infancy of, and/or evolving technological development associated with, confined, aquifer-hosted lithium-brine exploration plays.

In establishing a cutoff grade, the QP must realistically reflect on the location, deposit scale, continuity of mineralization, assumed mining method, metallurgical processes, costs and reasonable long-term metal prices appropriate for any deposit. The cutoff value must be relevant to the grade distribution modelled for the mineral resource, and represent the lowest grade, or quality, of mineralized material that qualifies as being economically mineable.

This Technical Report has shown:

1. Standard Lithium has established brine access agreements with a historically/presently permitted and active hydrocarbon operator.
2. The SWA Property is in southern Arkansas, a region that has over 50-years of brine processing and production experience (e.g., LANXESS and Albemarle; albeit for bromine extraction from the brine).
3. The Smackover Formation aquifer from which the brine is being produced is massive; it underlies parts of 6 U.S. States (Alabama, Arkansas, Florida, Mississippi, Louisiana, and Texas) and Bromine production occurs in three separate counties within southern Arkansas (Union, Columbia, and Lafayette).
4. The brine access method is straight-forward; no traditional mining is required as the brine is accessed from: 1) existing and operating active wells, or 2) by scrubbing out and perforating suspended and/or abandoned wells.
5. While predicting future lithium prices is challenging, the demand for lithium in batteries, and therefore lithium pricing, has increased since the early 2000s.

With respect to assigning a cutoff, it is worth assessing the lithium content of the brine at the SWA Property, which ranges from 132 mg/L (well Purser 2) to 461 mg/L (well MKP#21). Because of the limited number of brine analytical results and fact that if Standard Lithium produces brine from the SWA Property it will represent a 'blended' brine mixture, it is reasonable to justify a cutoff that represents the lower grade wells in the resource model and/or Standard Lithium's southern Arkansas properties.

A cutoff of 50 mg/L lithium was used in Standard Lithium's LANXESS lithium-brine resource estimate (Eccles et al., 2018), and this value is believed to represent the lowest grade, or quality, of mineralized material in Standard Lithium southern Arkansas lithium-brine projects. It is the opinion of the author that a cutoff of 50 mg/L lithium is acceptable. It is possible that this cutoff will be adjusted in future Technical Reports with higher levels of resource/reserve classification.

14.9.6 Step 7: Mineral Resource Reporting: SWA Property Inferred Lithium-Brine Resource Estimations

The SWA Property lithium-brine resource estimate is classified as 'inferred' according to the CIM definition standards. It is the opinion of the author that the project requires further detail to elevate the resource to a higher classification level. This work includes additional brine sampling and ongoing brine processing test work toward the development of a modern lithium extraction technology. The resource estimations presented in this Technical Report are based on the classical Lithium-brine equation, *Lithium Resource* = $A \times T \times P \times C$, where, A = area of aquifer; T = thickness of aquifer; P = porosity of aquifer; and C = concentration of Lithium in brine (e.g., Collins, 1976; Gruber et al., 2011).

Where possible, due diligent effort was considered to obtain the best-use values for these parameters. As such, the updated SWA Property inferred lithium-brine resource estimation which is presented as a total (or global value), was estimated using a unitised resource area and the following relation in consideration of the North and South resource areas, and the Upper and Middle Smackover Formations within those resource areas:

Lithium Resource = Total Volume of the Brine-Bearing Aquifer X Average Effective Porosity X Percentage of Brine in the Pore Space X Average Concentration of Lithium in the Brine.

Resources have been estimated using a cut-off grade of 50 mg/L lithium. With respect to units of measurement, 1 mg/L = 1g/m^3. If concentration is in mg/L and volume in m^3, then the calculated resource has units of grams. (1 g/m^3 x 1 m^3 = 1 gram or 0.001 kg).

The main updated 2021 SWA Property inferred lithium-brine resource estimation, which supersedes and replaces the 2019 mineral resource, is estimated at 225,000 tonnes of elemental Li (248,000 tons elemental Li; Table 14-14). The total lithium carbonate equivalent (LCE) for the main resource is 1,195,000 tonnes LCE (1,318,000 tons LCE). Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve.

Table 14-14. The updated (2021) and unitised SWA Property Inferred Lithium-Brine Resource Estimation. The grey-shaded 'total' column represents the main resource. The resource is also subdivided by resource area (i.e., North and South resource areas) and by formation (i.e., Upper and Middle Smackover Formations).

	Upper Smackover Formation		Middle Smackover Formation		
Reporting parameter	**South Resource Area**	**North Resource Area**	**South Resource Area**	**North Resource Area**	**Total (and main resource)**
Aquifer volume (km^3)	2.852	4.226	0.704	1.080	8.862
Brine volume (km^3)	0.281	0.416	0.071	0.110	0.878
Average lithium concentration (mg/L)	399	160	399	160	256
Average effective porosity	10.045	10.045	10.343	10.343	10.105
Total elemental Li resource (tonnes)	112,000	67,000	28,000	18,000	**225,000**
Total elemental Li resource (tons)	123,000	73,000	31,000	19,000	**248,000**
Total LCE (tonnes)	596,000	354,000	152,000	93,000	1,195,000
Total LCE (tons)	657,000	391,000	167,000	103,000	1,318,000

Notes:

[1] Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve. The estimate of mineral resources may be materially affected by geology, environment, permitting, legal, title, taxation, socio-political, marketing, or other relevant issues.

[2] The weights are reported in metric tonnes (1,000 kg or 2,204.6 lbs) and United States short tons (2,000 lbs or 907.2 kg).

[3] Numbers may not add up due to rounding of the resource values percentages (rounded to the nearest 1,000 unit).

[4] In a 'confined' aquifer (as reported herein), porosity is a proxy for specific yield.

[5] The grey-shaded 'Total' volume and weights are estimated at average effective porosities as geostatistically-derived for the North and South resource areas. The brine in pore space is assumed to be 98% brine.

[6] The SWA Property lithium brine project estimation was completed and reported using a cutoff of 50 mg/L Li.

[7] In order to describe the resource in terms of industry standard, a conversion factor of 5.323 is used to convert elemental Li to Li_2CO_3, or lithium carbonate equivalent (LCE).

With respect to specific parameters in the total (and main) resource column in Table 14-14:

- The Total Aquifer Volume, Total Brine volume, Total Li Resource, Total LCE Resource is the sum of all 4 sub-resources (i.e., North and South resource areas and Upper and Middle Smackover formations).
- The total average porosity was calculated using the equation:

$$\frac{Total\ Brine\ Volume}{Total\ Aquifer\ Volume * 0.98}$$

- The total average Li concentration (mg/L) was calculated using the equation:

$$\frac{Total\ Li\ Resource}{Total\ Brine\ Volume * 1000 * 1^{-9}}$$

Where,

- 'Total Li Resource' is in tonnes;
- 'Total Brine Volume' is in m^3; and
- the '1,000' is used to convert m^3 to Litres.

The total (and main) resource in Table 14-14 includes the breakdown of how the resource was calculated by area (i.e., North and South resource areas) and by formation (i.e., Upper and Middle Smackover formations). The information shows that the:

- Upper Smackover Formation in the South resource area contains the highest amount of LCE (596,000 tonnes; 657,000 tons), or more than double the next sub-resource area, which include the following estimations from highest to lowest LCE;
- Upper Smackover Formation - North resource area (354,000 tonnes LCE; 391,000 tons LCE);
- Middle Smackover Formation - South resource area (152,000 tonnes LCE; 167,000 tons LCE); and finally, the
- Middle Smackover Formation - North resource area (93,000 tonnes LCE; 103,000 tons LCE).

14.9.7 Reconciliation of Mineral Resources

With respect to reconciliation of resources, the updated 2021 SWA Property resource is 49% larger than the 2019 resource estimate. This difference is directly related to the contemplated unitisation of the resource area, which changed from 11,033 net mineral hectares (27,262 net mineral acres) to a unitised area that encompassed 14,638 gross mineral hectares (36,172 gross mineral acres). The change in resource area yielded total aquifer volumes that increased from a net acreage of 7.661 km^3 in 2019 to a gross acreage of 8.862 km^3. The other defining factor is a change from the net ownership value of approximately 74% in 2019 to a gross ownership value of being able to access 100% of the brine via the unitised area.

The updated resources do not represent a 100% or greater change in the total mineral resources at the SWA Property, and no new scientific or technical information was provided by Standard Lithium, or considered, during the preparation of the SWA Property 2021 Inferred Lithium-Brine Resource Estimations.

15 Mineral Reserve Estimates

Mineral reserves have not been estimated.

16 Mining Methods

16.1 Estimated Brine Production Capacity

16.1.1 Methodology

The inferred lithium brine resource estimate presented in Table 14.14 represents the brine resource present on the SWA Property that is potentially available for extraction. The lithium-rich brine from the Upper and Middle Smackover formations is proposed to be pumped from a network of production wells to ground surface and processed to remove the lithium and produced LHM. The lithium-depleted brine exiting the central processing plant could then be re-injected back into the same aquifer system through a network of brine injection wells, which are located distally from the brine supply well network. The actual recoverable amount of lithium will depend on the hydraulics of Upper and Middle Smackover formations and the design of the production and injection well networks. A key constraint on the lithium brine production rate and projected project lifespan is the requirement to minimize the breakthrough of lithium-depleted injection brine being pumped from the production brine supply well network, which would in turn reduce the lithium grade of the produced brine.

A numerical groundwater flow model was developed using the industry standard FEFLOW groundwater modelling platform to design the well networks for extracting the lithium-rich brine from the formation and to re-inject lithium-depleted brine from the central processing facility back into the formation. The numerical model was constructed using site data and interpreted hydrostratigraphic maps over the SWA Property (discussed in Sections 7 and 9) and published geological maps over the regional scale (AGC (1950); USGS (1968)). The model was parameterized using estimates of hydraulic conductivity and storativity discussed previously (Section 14.5).

Particle tracking is a numerical modelling tool that can be used to show the area from which brine originates to supply a well network extracting brine at specified pumping rates (i.e., the capture zone of the production well network). Particle tracking can also be used to show the advective front of brine depleted in lithium that is introduced into the aquifer through a network of injection wells. The particle tracking approach accounts for the advective component of transport – the transport of solutes moving with the flow of brine. It does not account for the transport mechanisms of dispersion and diffusion or transport attenuation processes such as adsorption or decay. Particle tracking was used to determine the simulated extraction area (i.e., the footprint over which the lithium-rich brine is targeted for extraction) of the SWA Property.

16.1.2 Production and Injection Well Network Design

The Upper and Middle Smackover formations are capable of producing very large volumes of brine as evidenced by decades of production data from the Albemarle and LANXESS brine operations immediately east of the SWA Property. Records from the Arkansas Oil and Gas Commission indicate brine production rates from southern Arkansas are generally on the order of 250 to 300 million US barrels annually (Figure 6-1, Table 6-1).

Factors that influence an aquifer's yield, or its ability to supply brine to a pumping well network, include transmissivity (the hydraulic parameter that describes the resistance to brine movement when a hydraulic gradient is applied), storativity (the parameter that describes the amount of brine released from storage when the hydraulic head is decreased) and the available hydraulic head (the height of the formation's hydraulic head above the top of the aquifer).

The targeted brine supply area of the SWA Project is the South resource area which has been interpreted to have an average lithium grade of 399 mg/L (Section 14.8) and an estimated brine volume of 0.352 km^3 (Table 14-14).

The rationale for supplying all of the brine from the South resource area and to reinject it back into the North resource area is to:

1. Simplify the modelling exercise as a uniform, high brine grade area that can be used for supply; and,
2. Maintain all brine related pumping and disposal activities within the proposed footprint of utilisation.

The general strategy for placing wells in the numerical model was to space production wells throughout the southern portion of the South resource area and injection wells throughout the northern area of the North resource area. Through an iterative set of simulations, a configuration for the placement of production and injection wells was developed which maximized the size of the area capturing brine from the South resource area without injection water reaching the production wells over an operation lifespan of 20 years.

16.1.3 Estimated Brine Production

Table 16-1 summarises the brine production and reinjection simulated with the final optimized numerical model.

Table 16-1. Summary of brine production and injection well networks

Summary of Brine Production Well Network		
Number of brine production wells	23	-
Total brine production rate from all wells – continuous operation	39,450	m^3/day
Total brine production rate from all wells – operating 8,000 hours annually	1,800	m^3/hour
Range in individual brine production well pumping rates	200 to 2,100	m^3/day
Average brine production well pumping rate per well – continuous pumping	1,715	m^3/day
Average production well pumping rate per well – pumping 8,000 hours annually	78	m^3/hour
Summary of Injection Well Network		
Number of brine injection wells	24	-
Total brine injection rate from all wells – continuous operation	43,390	m^3/day
Total brine injection rate from all wells – operating 8,000 hours annually	1,980	m^3/hour
Range in individual brine injection well pumping rates	Same rate for all wells	
Individual brine injection well pumping rate – continuous pumping	1,810	m^3/day
Individual brine injection well pumping rate – pumping 8,000 hours annually	86	m^3/hour

Results from the optimized brine supply and injection well network design simulation are summarised as:

- the Upper and Middle Smackover formations in South resource area are capable of supplying brine for the 20-year operational life assumed for the simulation;

- the Upper and Middle Smackover formations in the North resource area are capable of reinjecting brine depleted in lithium for the 20-year operational life assumed for the simulation;
- at the end of the 20-year operation simulation a buffer of at least 500 m separates the furthest edge of the production well network capture area and the advective front of the injected brine depleted in lithium. This indicates no breakthough of reinjected brine depleted in lithium being captured by the brine supply well network;
- dispersive mixing between the capture area of production wells and the injected brine is expected to be minor due to the width of the separation buffer;
- the production wells rates are highest in the western portion of Property and the lowest simulated brine supply production rates correspond to the east-central portion of the South resource area where the property width is the narrowest.

Assumptions used in developing the numerical model included the following:

- the model was run in steady-state mode, implying pumping and injection hydraulic stresses represent long-term, average conditions;
- pumping and injection rates were assigned for the Albemarle and LANXESS operations based on historical data from the Arkansas Oil and Gas Commission
- any hydraulic stresses caused by oil and gas operations were not included and would be considered insignificant;
- a uniform porosity value of 10% was assigned, consistent with average porosity measured over the SWA Property (Table 14-3).

16.2 Wellfield Overview

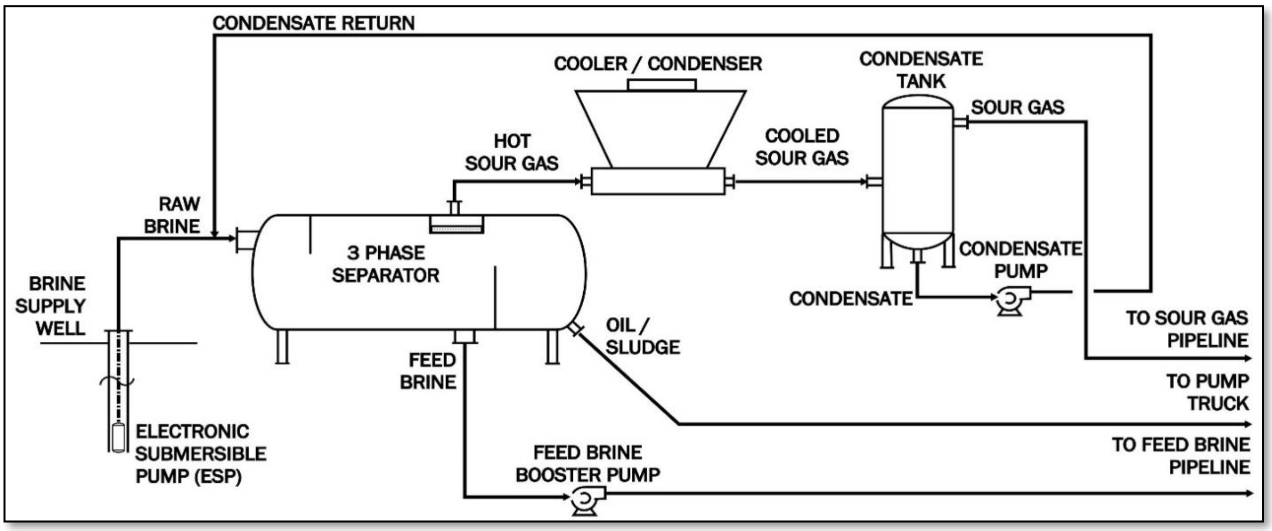
Brine extraction and disposal will occur using a conventional brine supply and injection wellfield as outlined in Section 16.1. A network of twenty-three (23) brine supply wells will produce from the Smackover Formation in the South resource area. The brine supply wells will produce between 200 m^3/day and 2,100 m^3/day with an average rate of 1,715 m^3/day. The average brine production rate will be 1,800 m^3/hr (7,925 US gallons per minute) during the 8,000 hours in the operational year. The supply wells, as modelled, are grouped into five (5) multi-well pad facilities to minimize initial capital expenditure and improve long-term maintainability. Brine from the supply facilities will be conveyed from the five multi-well pads to the single processing facility by a network of underground fiberglass pipelines totaling approximately 18.3 km (11.4 miles) in length. After processing, the lithium-depleted brine will be returned to the North resource area by a pipeline system 20.3 km (12.6 miles) in length to a network of 24 brine injection wells completed in the Smackover Formation. As with the supply wells, the injection wells are proposed to be grouped into five (5) multi-well pad facilities. All extraction and reinjection will occur in the single unitized area to maintain reservoir pressures.

16.3 Wellfield Configuration

16.3.1 Production Wells

The brine supply wells will extract the raw brine from the Smackover Formation on a continuous, 24-hour, 365 days per year operation. Operational time has been estimated to be 8,000 hours per year to account for ongoing maintenance, system upsets, weather outages, etc. An 800 HP electric submersible pump (ESP) will be installed in each production well that will pump the brine to the surface through a 17.8 cm (7 inch) tubing as depicted below in Figure 16-1.

Figure 16-1. Supply well process



As the brine is pumped to the surface, natural gas (usually sour in the project area) will degas out of the brine as the pressure drops. The brine, sour gas, and trace amounts of oil and solids (sludge) will be separated from one another at the wellheads using three-phase separators. The brine and sour gas streams produced will be sent from the separators to the main processing facility in pipelines. The oil/sludge mixture that is separated from the brine will be stored in tanks on the well pad and periodically removed via a pump truck for further processing at a local refinery or by a 3rd party.

Brine from the brine supply wells will be combined prior to leaving the well pad into single headers and “boosted” with pumps to deliver it to the central processing facility via a common brine pipeline. Brine variability is reduced by combining and mixing all the brine streams at the well pads and from all the well pads in the brine pipelines. Brine pumped from production wells and well pads through the brine pipeline is discharged to a large capacity brine receiving tank at the main processing facility.

Pressurized hot sour natural gas, containing light hydrocarbons (i.e., ethane, propane and butane), hydrogen sulfide, carbon dioxide and water vapor, separated from the brine in the three-phase separators will be cooled to condense out higher boiling point condensable hydrocarbons and water. The liquids (condensate) will be separated and returned to the three-phase separator feed. The “dried” sour gas from all of the brine supply wells will be collected into a single sour gas pipeline and delivered to the central processing facility (CPF). At the CPF, the sour gas will be transferred into an existing sour natural gas gathering pipeline supplying sour gas to the nearby Mission Creek Dorcheat Gas Plant where it will be sweetened for beneficial re-use.

16.3.2 Injection Wells

Once the lithium is removed from the brine, barren brine (or lithium-free brine) is then disposed of through the injection wellfield in the North resource area. A network of pipelines connects the

CPF to the injection (or disposal) wells. Like the supply wells, the injection wells will be grouped into five (5) multi-well pad facilities. Barren brine is delivered from the main processing facility by brine pumps to the well pads. The barren brine is pumped down through the injection wells into the Smackover Formation. The reinjection of the barren brine is necessary to maintain the pressure in the Smackover Formation aquifer.

16.4 Drilling Program

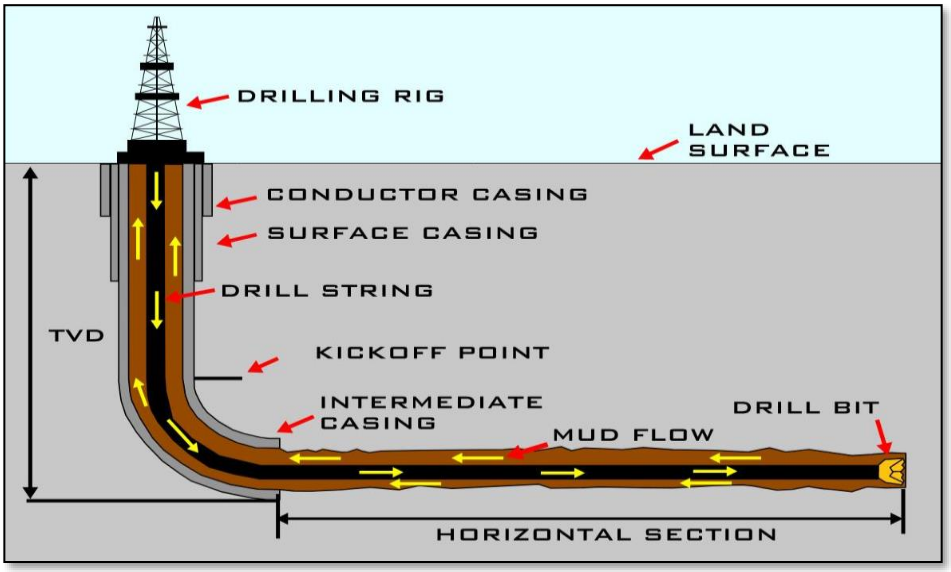
16.4.1 Well Details

The supply and injection facility/well locations and drilling methodologies used for each were chosen in an effort to maximize production and minimize costs and environmental impacts. The well design and drilling methodologies included in the wellfield plan for this project are detailed below.

- Vertical Wells – Vertical wells are drilled at a near vertical approach angle to the target location in the Smackover Formation. These wells have the lowest capital cost but will only be used for access to targets in the Smackover Formation directly below the multi-well pads.
- Directional Wells – Directional wells are initially drilled at a near vertical angle, but they eventually deviate with an angled approach to the target well location. These wells typically carry a greater capital and maintenance cost but allow multiple wells to be drilled from one surface location which reduces the overall environmental impact at the surface and minimizes costs by sharing the required surface resources and infrastructure. Directional wells also typically provide additional bore length in the "pay zone" than vertical wells which usually results in increased production/injection rates from the well.
- Horizontal Wells – Horizontal wells are similar to directional wells but are unique in that they continue their bend or "build" at the end of the well to allow the well tubing to approach the target well location at an angle that is in line with target formation. This allows the horizontal wells to provide an elongated "horizontal" stretch of well boring directly in the "pay zone" providing increased production and flexibility for the well location.

Figure 16-2 provides an illustration of the typical components for wells (in this case a horizontal well).

Figure 16-2. Well Diagram (Horizontal)



Additional details for each of the supply (production) and injection wells are provided in Table 16-2.

Table 16-2. Conceptual design details for the proposed supply and injection wells

	Supply Wells			Injection Wells	
Well Details	**Vertical**	**Directional**	**Horizontal**	**Vertical**	**Directional**
Quantity of Wells	4	14	5	5	19
Average Depth (m / ft)					
- Target Depth from Sea Level	2,652/ 8,700	2,721/ 8,925	2,652/ 8,700	2,530/ 8,300	2,530/ 8,300
- Wellhead Surface Elevation	92/ 300	92/ 300	91/ 300	92/ 300	92/ 300
- True Vertical Depth (TVD)	2,744/ 9,000	2,812/ 9,225	2,744/ 9,000	2,622/ 8,600	2,622/ 8,600
- Measured Depth (MD)	2,744/ 9,000	3,643/ 11,950	4,164/ 13,660	2,622/ 8,600	3,109/ 10,200
Casing Details (cm / in)					
- Conductor Casing	60.690/ 24.000	60.690/ 24.000	60.690/ 24.000	50.800/ 20.000	50.800/ 20.000
- Surface Casing	40.640/ 16.000	40.640/ 16.000	40.640/ 16.000	33.973/ 13.375	33.973/ 13.375
- Intermediate Casing	27.305/ 10.750	27.305/ 10.750	27.305/ 10.750	Not Req'd	27.305/ 10.750
- Production Casing	17.780/ 7.000	17.780/ 7.000	17.780/ 7.000	24.448/ 9.625	24.448/ 9.625

16.4.2 Rig Details

The brine supply and injection wellfields will require heavy-duty, rotary-type, well drilling rigs due to the large well bore size and depths required for each of the wells (see Table 16.1 for supply and injection well bore size details). Multiple drilling rigs will be deployed to complete the drilling operations in the required timeframe (schedule duration). Local drilling service providers will be used, as far as possible, to minimize the mobilization costs associated with the drilling rigs.

16.4.3 Drilling Schedule

The total drilling effort for the wellfields will require approximately 12 months to complete for a 10 rig/crew arrangement or 24 months for a 5 rig/crew arrangement. A 10 rig/crew arrangement was assumed for the purposes of this assessment. Further evaluation should be included in the next phase of work to understand the feasibility of the current approach.

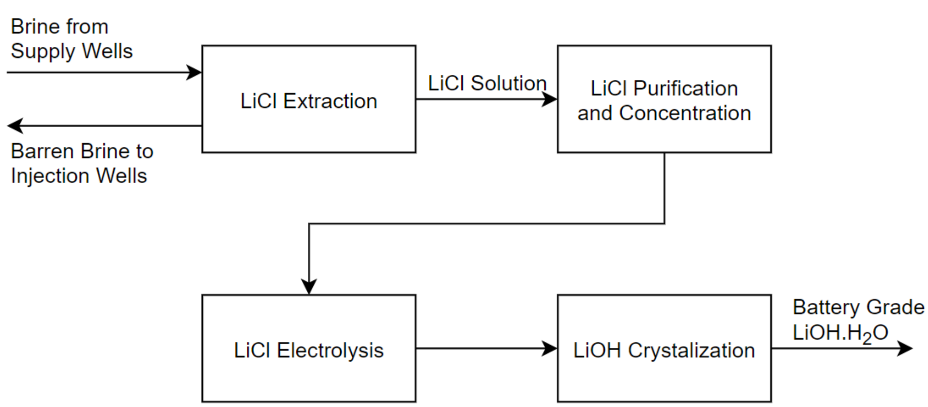
17 RECOVERY METHODS

Standard Lithium will produce battery-quality LHM ($LiOH•H_2O$) from Smackover Formation brine. Lithium-containing brine will be produced from brine supply wells, as discussed in Section 16. The produced brine will be pipelined to the CPF for further processing to the final product. Average LHM production will be 30,000 tonnes/year over a 20-year operating timeframe. The lithium recovery from the brine to the final product is about 90%. The overall process Block Flow Diagram (BFD) is shown in Figure 17-1. The production process includes the following major unit processes:

- lithium chloride extraction from the brine
- lithium chloride purification and concentration
- lithium chloride electrolysis to convert to lithium hydroxide
- LHM crystallization and drying

These processes are described below.

Figure 17-1. Overall block flow diagram of lithium hydroxide monohydrate production from Smackover Formation brine



17.1 Brine Production and Delivery

Brine will be delivered from the wellfield via pipelines to the brine receiving tank at the CPF as discussed in Section 16.

17.2 Production of Purified Lithium Chloride Solution

The first step in producing LHM will be the production of purified and concentrated lithium chloride solution in the CPF. The process to be used is shown in Figure 17-2 and discussed below.

17.2.1 Preparation of the Feed Brine

Produced brine from the brine receiving tank will be delivered by pipeline to the lithium chloride plant in the CPF. The blended produced brine is estimated to have a lithium concentration of about 400 mg/L as lithium (see Table 17-1). The brine will be hot (>70°C), highly saline (TDS of about 300,000 mg/L), low in sulfate, and will have a density of about 1.2 g/cm^3. Sodium and calcium chlorides are the main constituents of the brines.

Prior to lithium extraction, the brine will be pre-treated. Suspended solids, dissolved gas, and crude oil will be removed, and the pH of the brine increased to near-neutral through the addition of caustic soda and/or ammonium hydroxide.

The brine will be vacuum-degassed to remove dissolved gases, including: hydrogen sulfide (H_2S), carbon dioxide (CO_2), methane (CH_4), other low-boiling-point hydrocarbons, and nitrogen (N_2). Gases separated from the brine in the vacuum-degassing process will be compressed and combined with the sour gas from the production wells that is separated in the field and pipelined to the Mission Creek Dorcheat Gas Plant.

The degassed brine can then be filtered using a submerged microfiltration membrane filter to remove fine particulates. The membrane brine filter will be backwashed periodically to remove captured solids. The fine solids removed from the incoming brine are disposed with the lithium free barren brine in the brine injection wells (see Section 17.2.3).

Table 17-1 Lithium content of the produced brine (feed to lithium extraction process)

Units	Component	Feed Brine
mg/L	Li	399

17.2.2 Lithium Extraction Process

The key unit process for the production of lithium chloride solution is the lithium-selective sorption extraction process. The process starts with sorbent loading.

In the loading process, pre-treated brine will be mixed with fine-grained, solid, lithium-selective sorbent creating a slurry in the loading reactor tanks. The sorbent selectively sorbs lithium ions from the brine in two counter-current loading reactors. A simplified BFD of the lithium extraction process is presented in Figure 17-2.

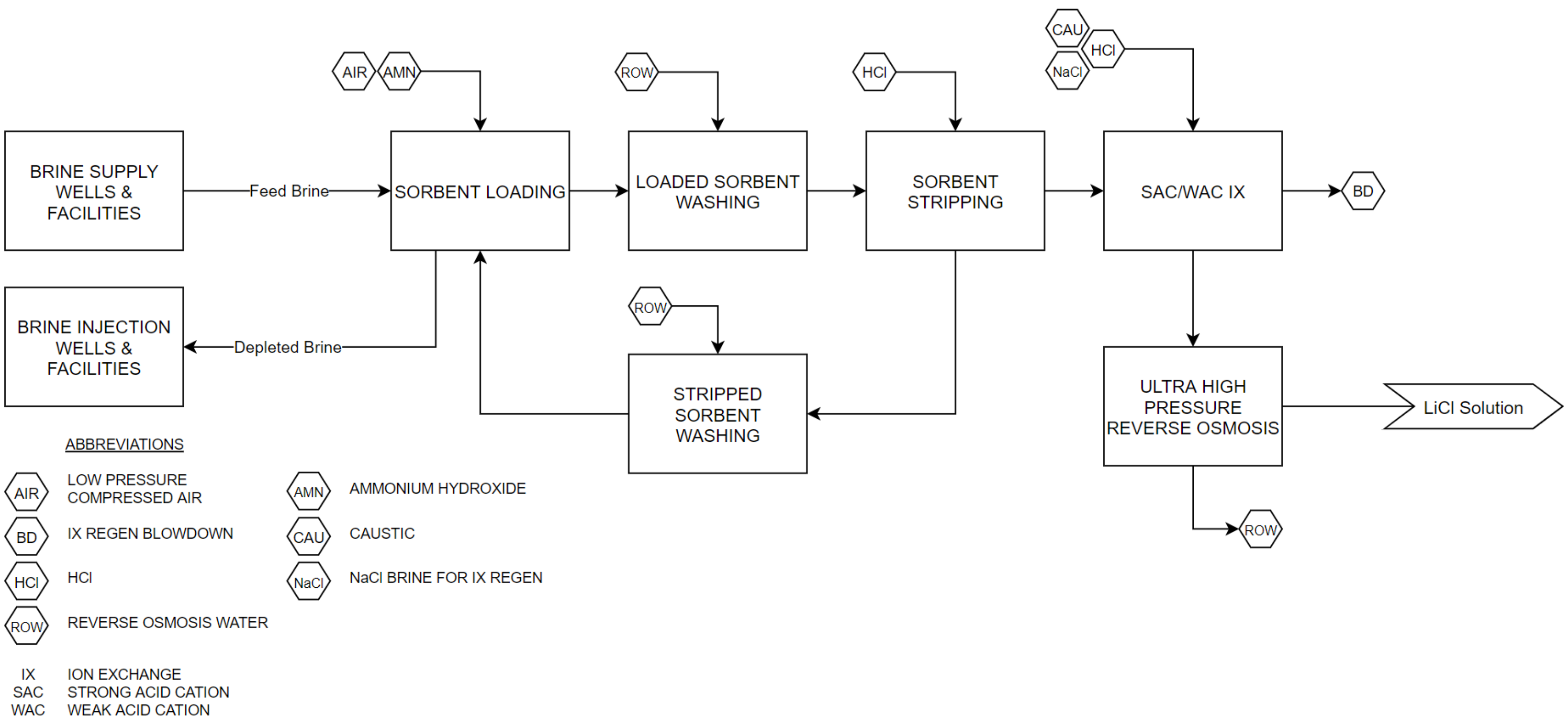
Ammonium hydroxide will be added to the loading reactors during the lithium extraction process to maintain the desired pH conditions.

The lithium-barren brine will be separated from the loaded sorbent slurry using submerged microfiltration membrane units inside the loading reactor tanks. The membranes used are fine hollow tubes arranged in vertical, multi-tube modules. Lithium-barren brine (permeate) is drawn through the walls of membranes from outside to inside and the lithium-loaded sorbent solids are left on the outside of the tubes as the brine passes through.

The lithium-loaded sorbent solids will be continuously removed from the outside of the membrane tubes by scouring with submerged aeration and periodic backwashing of the membranes using permeate. The loaded sorbent slurry is pumped from the loading process to the loaded sorbent washing process.

In the loaded sorbent washing process, the lithium-loaded sorbent slurry is washed with water in three (3) stages of counter-current decantation thickeners. The washed and thickened sorbent will then be pumped as a slurry to the stripping reactor for separation of the lithium from the sorbent.

Figure 17-2. Block flow diagram of lithium extraction process (lithium chloride plant)



17.2.3 Lithium Barren Brine Disposal

The lithium-barren brine (tail-brine) separated from the sorbent in the loading reactors using the submerged membranes will be pumped to the tail-brine tank where the pH will be adjusted, to achieve a final discharge pH of approximately 5.5. This pH is required to:

- avoid any precipitation issues in the brine injection wells;
- conform with anticipated discharge criteria of the regulatory agency (Arkansas Oil and Gas Commission); and
- meet best-practice guidelines for reinjection of tail-brine into the Smackover Formation.

Tail-brine from the lithium extraction process will be pumped via pipelines to brine injection wells for disposal. Twenty-four brine injection wells located in the North resource area are proposed to be used for disposal of lithium barren tail-brine (see Section 16).

17.2.4 Lithium Sorbent Stripping and Regeneration Process

In the proposed process, washed lithium-loaded sorbent is stripped to separate the lithium from the sorbent for recovery. Lithium-loaded and washed sorbent is contacted with dilute hydrochloric acid in a mixed stripping reactor. The stripping process generates lithium pregnant strip solution (PSS). The PSS will be separated from the barren sorbent in a thickener tank. The stripped sorbent is washed with fresh water in three (3) stages of counter-current decantation thickeners. The stripped and washed lithium-depleted sorbent will be then recycled back to the loading stage.

After washing, the PSS has a high ratio of lithium to the sum of the other dissolved metals and will contain 3-5 g/L of lithium. This enriched lithium chloride solution will then be further purified and concentrated.

17.2.5 Pregnant Strip Solution (Lithium Chloride) Purification and Concentration

The PSS from the stripping stage will undergo removal of residual divalent ions, including, calcium (Ca^{+2}) and magnesium (Mg^{+2}), using industry-standard ion exchange treatment. The treatment includes two stages of ion exchange.

The purified lithium chloride solution is then further concentrated to produce a lithium chloride concentrate using an ultra high-pressure reverse osmosis process and pumped to the LHM process facility.

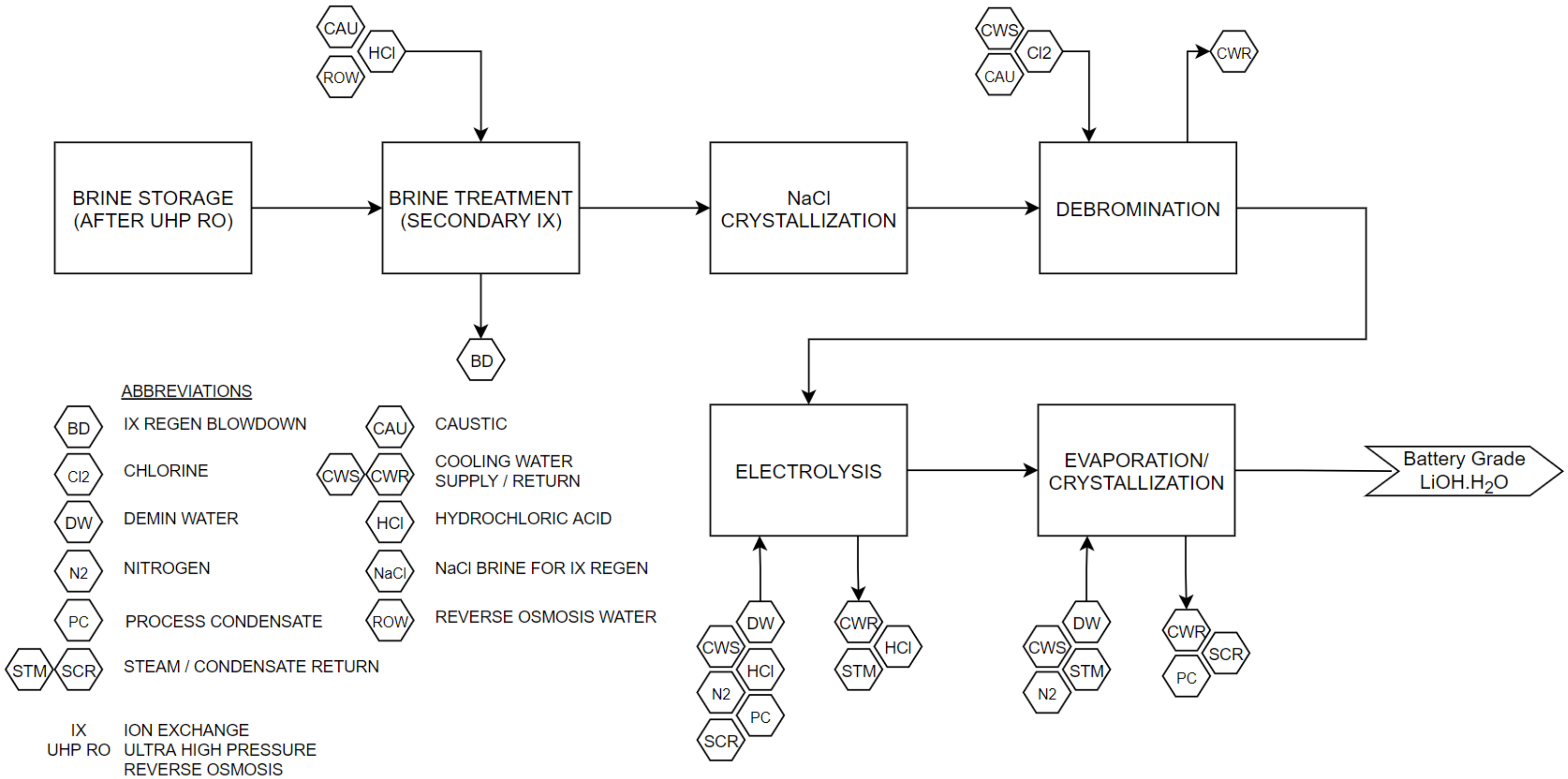
17.3 Production of Lithium Hydroxide Monohydrate

The LHM production process includes the following steps:

- an additional stage of ion exchange to remove any residual calcium and magnesium;
- further concentration of the lithium chloride concentrate and separation of sodium chloride from the solution using an evaporative crystallization process;
- electrolytic conversion of lithium chloride to lithium hydroxide;
- further evaporative crystallization of the lithium hydroxide into LHM; and
- drying and packaging in an inert atmosphere to produce dry LHM crystals.

The LHM production process is shown in the BFD presented in Figure 17-3.

Figure 17-3. Block flow diagram of lithium hydroxide monohydrate plant



Sodium chloride produced from the NaCl evaporator-crystallizer is dissolved to provide the pure brine required for regeneration of the ion exchange resin in the strong-acid-cationic (SAC) ion exchange process.

Chlorine gas produced from the electrolysis of lithium chloride to lithium hydroxide will be reacted with hydrogen, also produced by the electrolysis process, to produce hydrochloric acid. The hydrochloric acid is used in the sorbent stripping stage in the lithium extraction process and for regeneration in the weak-acid-cationic ion exchange process.

Condensate produced from the evaporation is used for washing in the lithium extraction process.

18 PROJECT INFRASTRUCTURE

The infrastructure required to construct and operate the proposed project is described below.

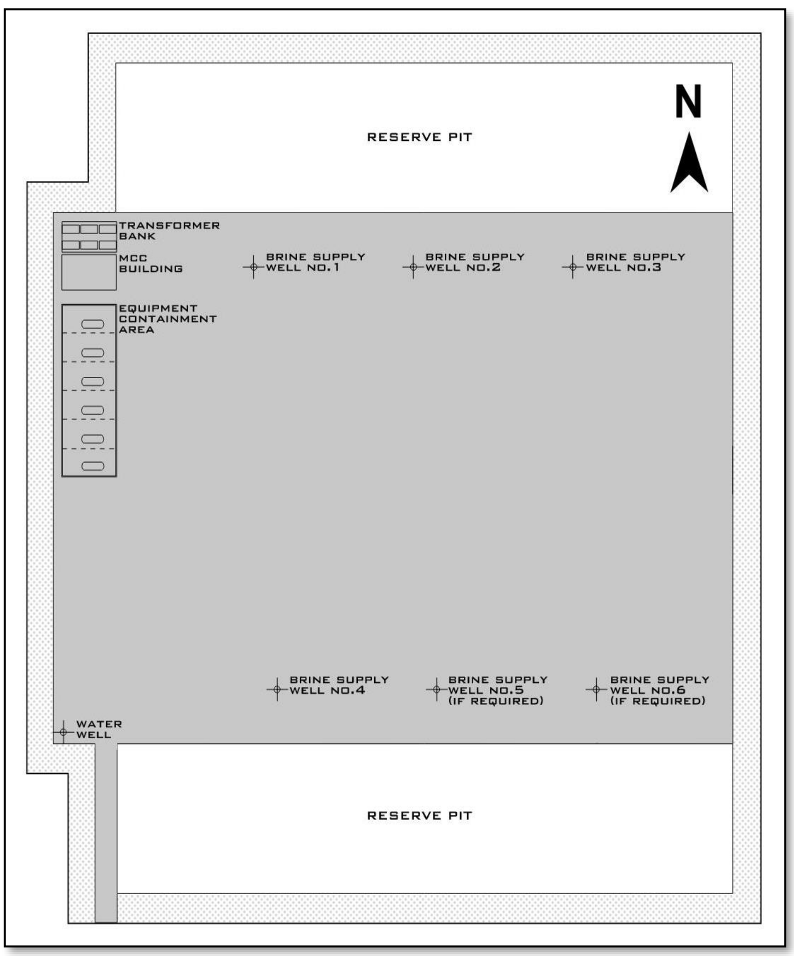
18.1 Brine Supply Wells Infrastructure

18.1.1 Wellfield

Brine is proposed to be extracted via a network of 23 brine supply wells located in the South resource area of the SWA Project. The wellfield will utilize the latest drilling technologies to provide an optimal multi-directional wellfield design that consolidates the surface locations of the wells into five (5) well pad locations. The well pad locations will be chosen following more definitive geological and hydrogeological siting studies conducted as part of the next pre-feasibility study(PFS) assessment.

The brine supply well pad facilities will provide an economical solution for the above ground utilities and infrastructure at each well by assembling 4 to 5 of the brine supply wells at each location and sharing or "pooling" their individual surface facilities to minimize upfront cost and improve operations and maintenance (see Figure 18-1).

Figure 18-1. Brine supply well pad conceptual layout



Each of the brine supply wells will be individually equipped with an electric submersible pump (ESP). The ESP's will pump the brine through a three-phase gravity separator to remove sour gas and crude oil from the brine before it is sent to the brine supply pipeline network via a booster pump.

18.1.1.1 Water Supply and Distribution

Each of the well pad facilities will be equipped with a 45 m (150 ft) deep (from surface) water well that will provide approximately 10 m^3/hr (45 US gpm) of water for drilling and routine well maintenance operations.

18.1.1.2 Power Supply

The supply well pad facilities will require approximately 12 megawatts (MW) total for routine operations of the facilities as outlined below in Table 18-1.

Table 18-1. Power consumption for the brine supply well facilities

Facility No.	Well Count	Operating Power (kW)	Annual Electrical Consumption (kWh)
Facility No.1	4	2,083	18,098,872
Facility No.2	5	2,604	22,623,590
Facility No.3	5	2,604	22,623,590
Facility No.4	5	2,604	22,623,590
Facility No.5	4	2,083	18,098,872
Total	23	11,977	104,068,513

Each of the well pad facilities will include a small, prefabricated metal motor control center (MCC) building, medium voltage drive, and a capacitor bank. The power supply to each facility will be from the South-West Arkansas Entergy power grid. New substations and transmission lines will likely be required for the facilities but have not been included at this time in the evaluation.

18.1.1.3 Compressed Air

Compressed air will be supplied via a single compressor at each well pad facility located within the MCC buildings.

18.1.1.4 Chemicals & Reagents

Chemicals and reagents required for operation and maintenance of the brine supply wells and well pad facilities will be stored within the equipment containment areas at each well pad facility. These include, but are not limited to, anti-scalant and anti-corrosion chemicals.

18.1.1.5 Auxiliary Infrastructure

The following auxiliary infrastructure will be required at each well pad facility but are not included in the evaluation at this time per the guidelines set by the AACE for a Class 5 estimate.

- Access roads to the facility
- Communication (internet to the site whether that be ethernet or wireless)
- Electrical substation and power distribution lines
- Metering stations for sour gas and brine

18.1.1.6 Pipelines

Brine will be transported via fiberglass pipelines from the booster pump at each well pad facility to the CPF. Sour gas removed from the brine at the well facilities will be transported to the CPF via high density polyethylene plastic (HDPE) pipelines. The assumed pipeline quantities and details are detailed below in Table 18-2.

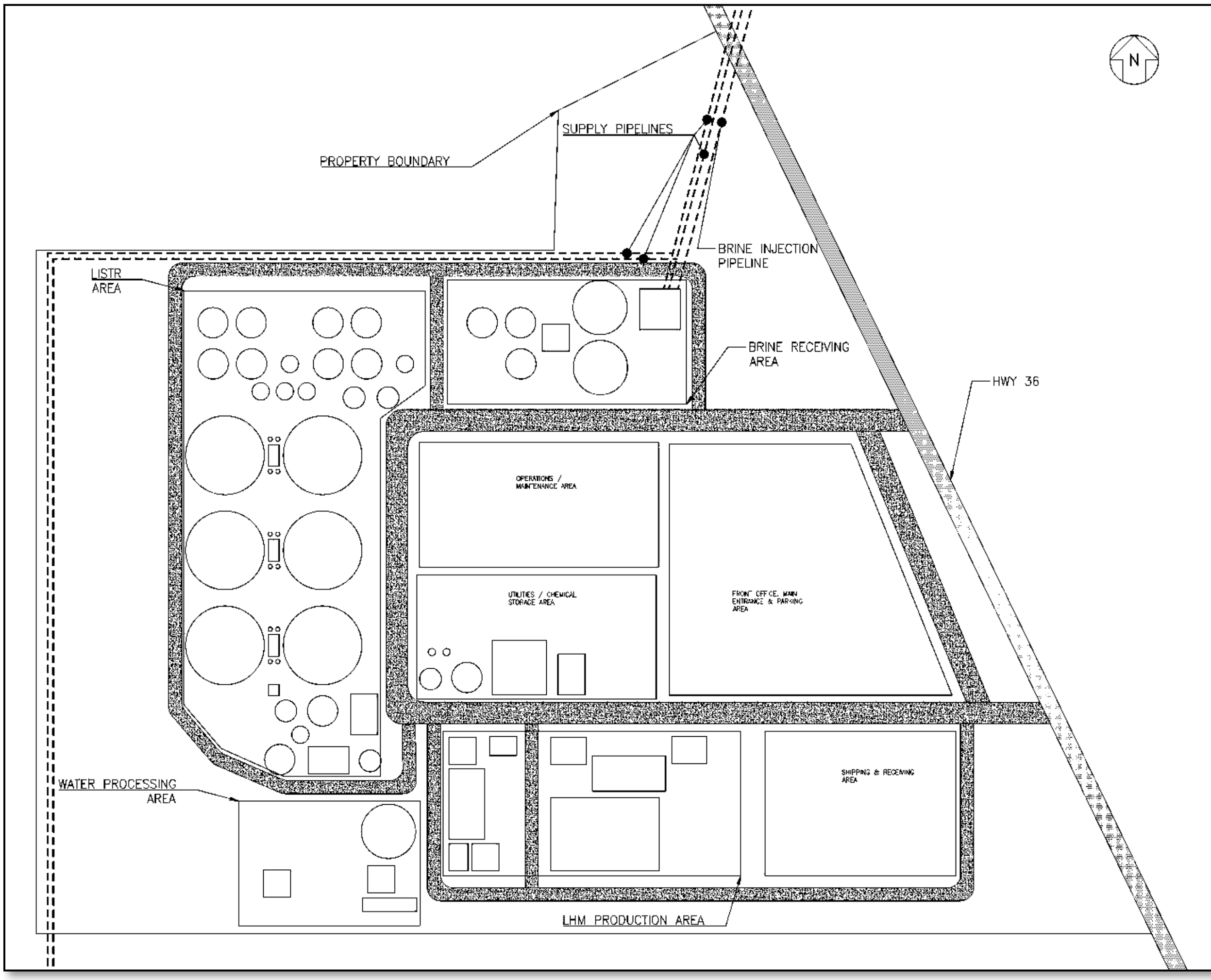
Table 18-2. Conceptual brine supply & sour gas pipeline details

Description	Material Type	Diameter	Length
Brine Supply	Fiberglass NOV Green Thread HP25	25.40cm (10”), 30.48cm (12”), 40.64(16”), 50.80cm (20”)	18.25 km (11.41 miles)
Sour Gas	HDPESDR-11/ PE3408	15.24cm (6”), 20.32cm (8”), 25.40cm (10”), 30.48cm (12”), 40.64(16”)	18.25 km (11.41 miles)
Total	-	-	36.5 km (22.82 miles)

18.2 Central Processing Facility Infrastructure

Road access to the CPF will be via Highway 36 and Highway 56. The main entrance to the CPF will be located approximately 10.4 km (6.5 miles) from the junction of Highway 36 and Highway 56. A conceptual layout showing the proposed location, process areas, and auxiliary facilities is provided below on Figure 18-2.

Figure 18-2. Central production facility conceptual layout



18.2.1 Fresh Water Supply and Distribution

Four (4) fresh water supply wells will be installed with one (1) spare to provide water to the CPF. The fresh water supply wells will be drilled to a depth of approximately 100 m (300 feet) below grade and designed to produce 380 m^3/hr (1,750 US gpm) of fresh water to the facility. Water will be sent from the wells to the well water/fire suppression storage tank where approximately 10,600 m^3 (2.8 million gallons) of fresh water will be stored for the plant as further defined below.

- Fire Water – The design of the tank will be such that 4,920 m^3 (1.3 million gallons) of water will be intrinsically reserved for fire water use.
- Process Water – Process water will be obtained directly from the tank without further processing for general plant use.
- Reverse Osmosis (RO)/Potable Water – RO water will be generated onsite using a RO treatment unit designed to produce 31.8 m^3/hr (140 US gpm) of RO-treated water primarily for use in the sorbent washing process, ion exchange units, demineralized water filtration unit, and potable water applications.

- Demineralized (Demin) Water – Demin water will be generated onsite using a demin filtration unit designed to produce 6.8 m^3/hr (30 US gpm) of demin water primarily used for startup in the cell house (EC-1600) and hydrochloric acid generation (X-1800) units.

18.2.2 Steam Supply

The CPF will be equipped with a natural-gas-fired boiler unit to provide approximately 114,000 kg/hr. (250,000 lb/h) of medium pressure steam to the plant. The steam will primarily be used in the evaporator/sodium chloride crystallizer unit but will also be used at the lithium hydroxide monohydrate crystallizer and various area heaters throughout the plant.

18.2.3 Power Supply

The CPF will require a power supply of approximately 19.8 megawatts (MW) and will consume roughly 159,000 MWh of electricity per year.

The power supply to the CPF will be from the South West Arkansas Entergy power grid. New substations and transmission lines will likely be required for the facilities but have not been included at this time in the evaluation.

18.2.4 Compressed Air

Compressed air will be supplied via a bank of rotary screw compressors. The compressor unit will be equipment with a refrigeration dryer system to control moisture content.

18.2.5 Sour Gas Disposal

The CPF will utilize an existing natural gas transmission pipeline tie-in on site to send sour gas downstream to the nearby Mission Creek Dorcheat Gas Plant for further processing.

18.2.6 Auxiliary Facilities

The CPF will include the following auxiliary infrastructure facilities:

- Access/Security Checkpoint
- Perimeter Fencing
- Weigh Scale(s)
- Internal Access Roads
- Communication (phone Lines, internet)
- Electrical Substation and Power Distribution Lines for Energy Supply
- Natural Gas Metering Station and Distribution Lines for Natural Gas Supply
- Sanitary Wastewater Disposal Lines and Processing Pond
- Solid Waste Disposal
- Buildings
    - Administrative Office & Laboratory
    - Warehouse(s)
    - Workshop(s)
    - Storeroom(s)
    - Shipping & Receiving

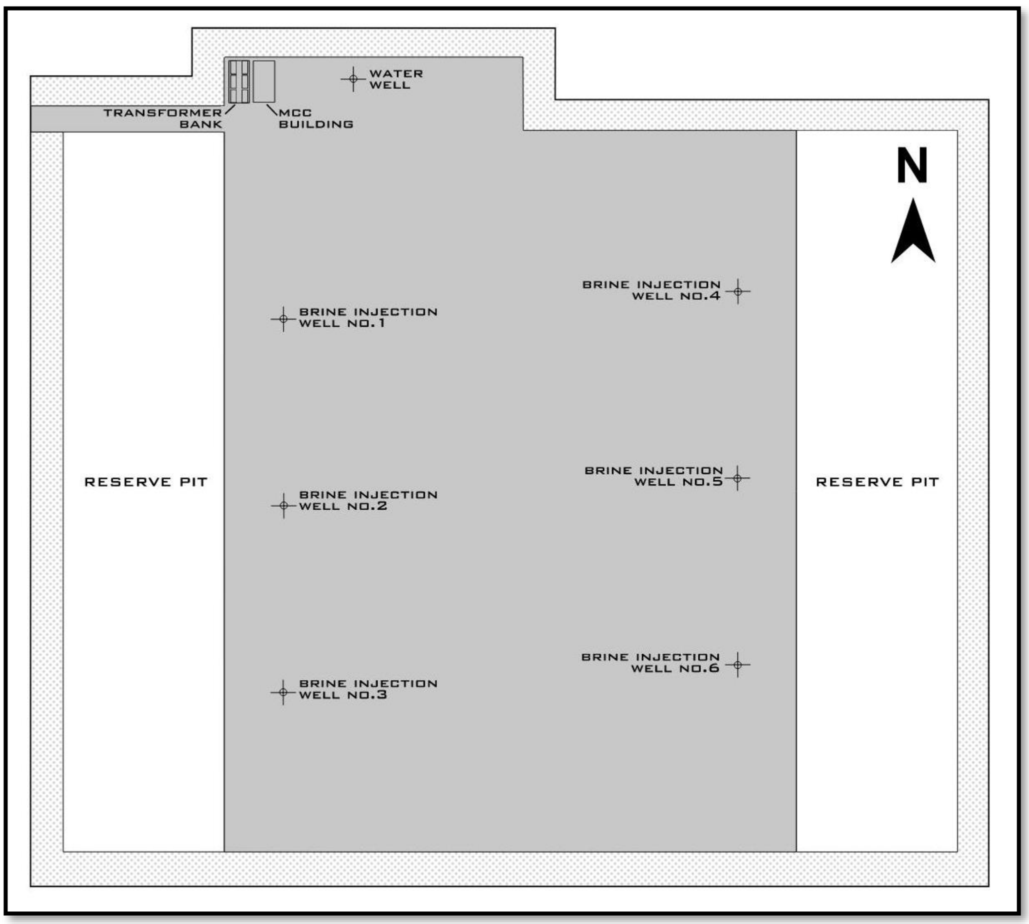
18.3 Barren Brine/Process Water Injection Wells Network Infrastructure

18.3.1 Wellfield

The CPF will discharge barren brine and process water (not to exceed additional 10% process water by volume). The tail-brine will be pumped from the CPF to a network of 24 brine injection wells located in the North resource area of the SWA Property. This wellfield will use the same drilling technology used in the supply field to consolidate the surface locations of the wells into 5 facilities. The injection well pad locations will be chosen following more definitive geological and hydrogeological siting studies conducted as part of the PFS assessment.

The brine injection well facilities will follow the same approach of the brine supply facilities by assembling 4 to 6 of the brine injection wells at each location to share or "pool" their individual surface facilities to minimize upfront cost and improve operations and maintenance (see Figure 18-3).

Figure 18-3.Brine injection facility conceptual layout



Each of the brine injection wells will be individually equipped with a booster pump to reinject the lithium barren brine back into the Smackover Formation.

18.3.1.1 Water Supply and Distribution

Each of the brine injection well pad facilities will be equipped with a 45 m (150 ft) deep (from surface) water well that will provide approximately 10m^3/hr (45 US gpm_) of water for drilling and routine well and well pad facilities maintenance operations.

18.3.1.2 Power Supply

The injection well pad facilities will require approximately three (3) megawatts (MW) total for routine operations of the facilities as further defined below in Table 18-3.

Table 18-3. Power Consumption for the Brine Injection Well Facilities

Facility No.	Well Count	Operating Power (kW)	Annual Electrical Consumption (kWh)
Facility No.1	6	739	6,327,977
Facility No.2	5	616	5,273,314
Facility No.3	5	616	5,273,314
Facility No.4	4	493	4,218,651
Facility No.5	4	493	4,218,651
Total	24	2,958	25,311,908

Each of the brine injection well pad facilities will include a small, prefabricated metal MCC building, medium voltage drive, and a capacitor bank. The power supply to each facility will be from the South-West Arkansas Entergy power grid. New substations and transmission lines will likely be required for the facilities but have not been included at this time in the evaluation.

18.3.1.3 Compressed Air

Compressed air will be supplied via a 5 hp compressor at each well pad facility. The compressors will be located within the MCC buildings.

18.3.1.4 Auxiliary Infrastructure

The following auxiliary infrastructure items will be required at each facility but are not included in the evaluation at this time per the guidelines set by the AACE for a Class 5 estimate.

- Access roads to the facility
- Communication (Internet to the site whether that be ethernet or wireless)
- Electrical substation and power distribution lines
- Metering stations for brine

18.3.2 Pipelines

Brine will be transported via fiberglass pipelines from the CPF to the booster pumps at each brine injection well pad and then to each individual injection well. The assumed pipeline quantities and details are detailed below in Table 18-4.

Table 18-4. Barren Brine Pipeline Details

Description	Material Type	Diameter	Length
Barren Brine	Fiberglass NOV Green Thread HP25	30.48cm (12”), 35.56cm (14”), 40.64cm (16”), 50.80cm (20”), 60.96cm (24”)	20.13 km (12.58 miles)
Total	-	-	20.13 km (12.58 miles

19 Market Studies and Contracts

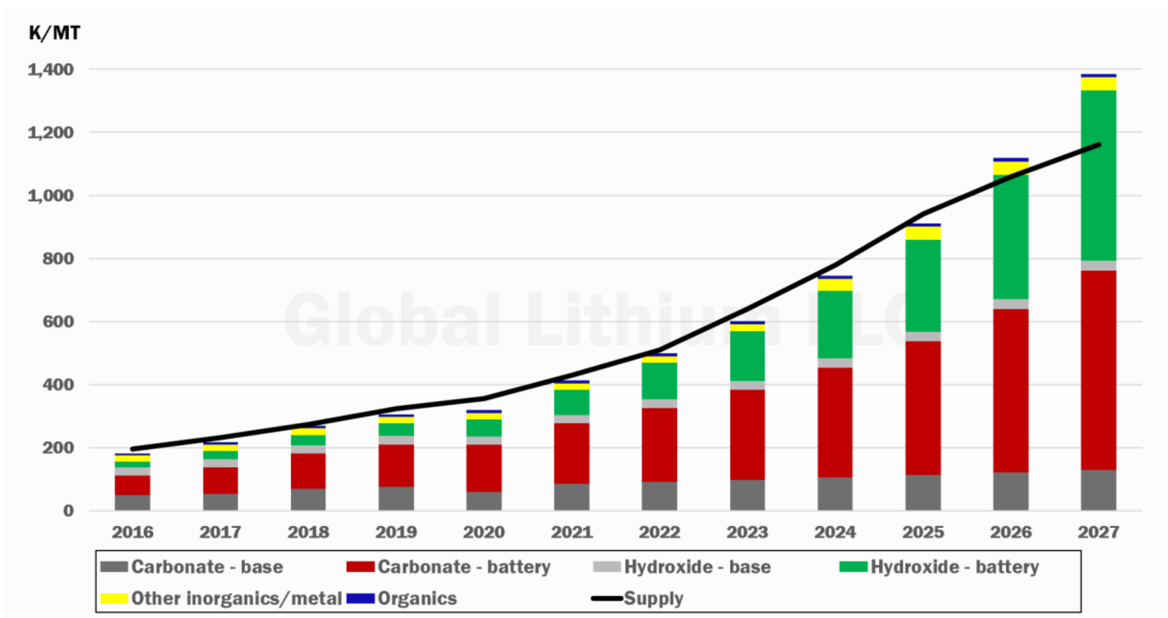
19.1 Background

Lithium demand is expected to grow by approximately 300% from 2020 to 2025 and 700% by 2031 based on a gradual global transition away from fossil fuels which will be replaced by increased use of renewable energy. A key component of this change is the phasing out of internal combustion engine (ICE) vehicles in favor of electric vehicles (EVs) and increased use of lithium-ion batteries in energy storage systems (ESS) for renewable power from wind and solar. The lithium industry is not adequately prepared for this transition. New lithium resources and improved technology for lithium extraction will be required to satisfy the coming exponential growth.

Lithium used in batteries is a specialty chemical as opposed to a commodity, which, due to the complexity of production, makes keeping up with demand even more challenging. Many lithium operations in production today were based on industrial demand for lithium, which required a product with much less stringent specifications than the battery industry. The forecast by Global Lithium LLC (shown in Figure 19-1) projects sustained lithium pricing strength over the next several years and, based on the demand growth and increasingly stringent quality standards, the lithium industry will struggle to supply in adequate volume to meet this growing demand.

The fact that lithium is now on the Unites States Government’s critical metals list makes a US-based lithium project more attractive, given that most of the world’s lithium hydroxide is currently produced in China. Major battery manufacturers and automotive OEMs are increasingly looking for more geographic diversity in their supply chains. Global Lithium’s supply and demand forecast, is lower than the consensus average of other lithium market forecasts.

Figure 19-1. Lithium Supply and Demand - Historical and forecast from 2016-2027 (used with permission from Global Lithium LLC)

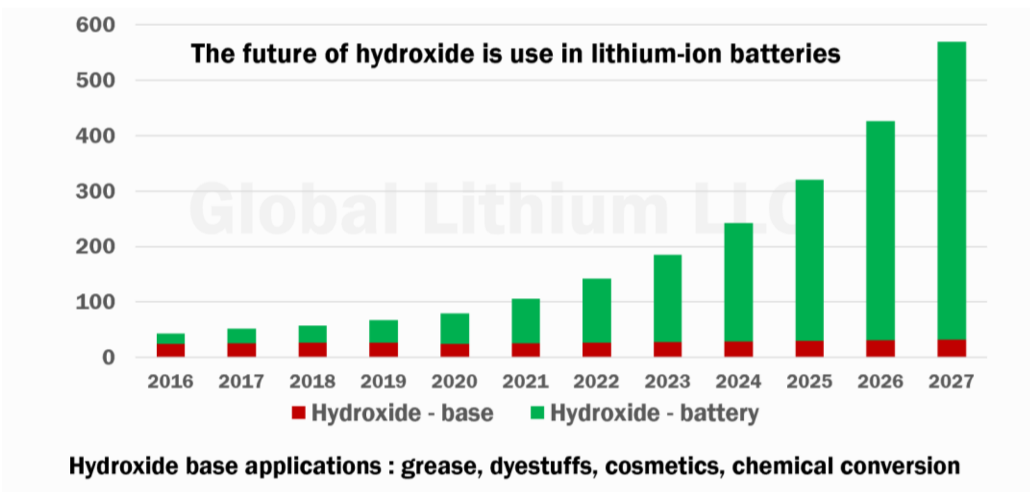


It will be challenging for lithium supply to stay ahead of lithium demand growth in the next decade even in the base case growth scenario. Lithium projects historically have come online one to three years later than announced and extended production ramp-up periods to achieve acceptable quality are also common.

When LCE demand reaches one million metric tonnes by the middle of this decade it will have taken over 60 years to achieve that volume. The second million tonnes will take approximately five years as the energy transition in both transportation and ESS for solar and wind power gains traction. Lithium is the most critical of battery metals required in the energy transition. Lithium-ion batteries can be made without nickel, cobalt or manganese but all cathode technologies depend on either lithium carbonate or lithium hydroxide as the lithium source.

Lithium hydroxide is expected to be the fastest growing form of lithium chemical over the next five years due to the growth of high nickel cathode in batteries used for electric vehicles where long range between charges is a priority. The longest range batteries require the use of lithium hydroxide rather than lithium carbonate for technical reasons. Projected growth of lithium hydroxide is depicted in Figure 19-2:

Figure 19-2. Lithium Hydroxide Demand - Historical and forecast from 2016-2027 (used with Permission from Global Lithium LLC)



Lithium supply is likely to become the critical path for EV adoption based on the fact it can take up to a decade to bring a greenfield lithium project online and takes only two to three years to build a battery gigafactory.

19.2 Price

Despite announced expansions by major lithium companies such as Albemarle, SQM and Ganfeng the industry has moved from a brief period of oversupply to what appears to be a sustained period of tight or inadequate supply. Delays of both new projects and expansions coupled with consolidation of the Western Australia hard rock precursor supply that feeds Chinese lithium chemical conversion capacity led to an approximately 300% increase in China spot prices between Q4 of 2020 and Q3 of 2021.

The lithium chemicals spot market in China normally has the highest prices due to the majority of supply coming from high cost domestic production. The market outside of China tends to operate on contracts ranging in length from six months to several years.

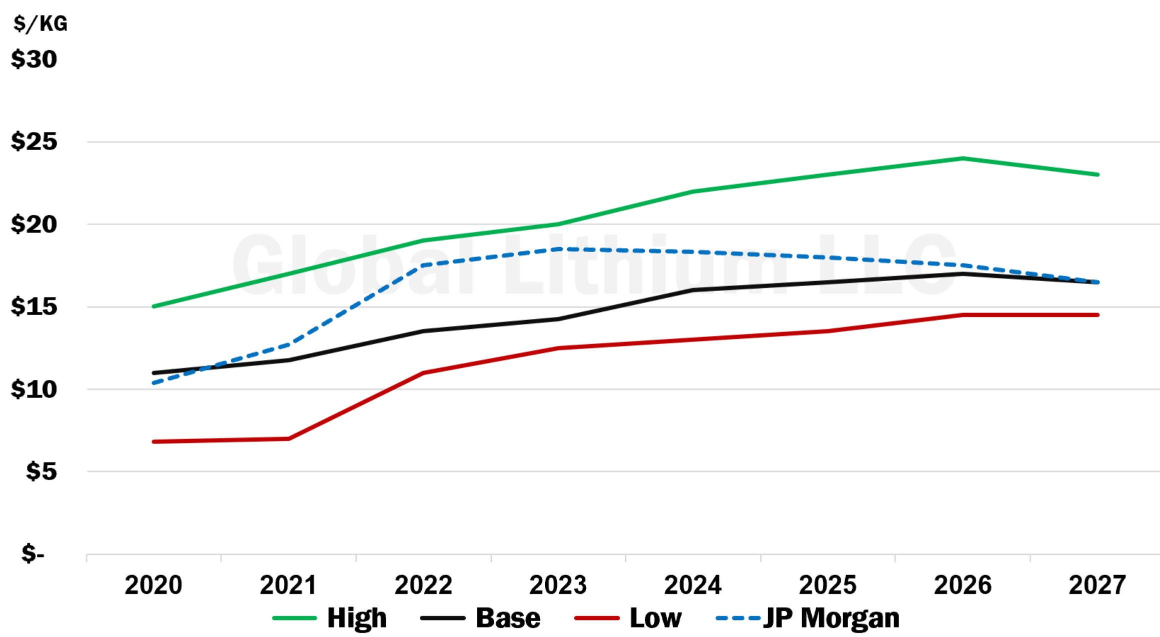
Shortages in the lithium supply chain begin to happen when capacity utilization is above 85 to 90% for an extended period. It should be noted that a portion of capacity additions will not be of sufficient quality to be used in battery applications, further exacerbating a tight supply situation.

Although China is the largest single market for battery quality lithium chemicals; Korea and Japan are also significant markets with each currently requiring over 40,000 MT of LCEs per year with a much higher growth rate in cathodes requiring lithium hydroxide. Korean and Japanese battery manufacturers have been very vocal about their desire to have alternatives to supply from China for competitive and political reasons.

The Global Lithium price forecast for lithium hydroxide is shown in Figure 19-3. It should be noted that there is not a globally consistent price for any lithium chemical. The China spot price is sometimes triple what a large cathode maker may be paying under a long-term contract signed at a time when price was low.

The high, base and low scenarios take pricing anomalies into consideration. The dotted line is J.P.Morgan's base case as of July, 2021 (J.P.Morgan Chase & Co., 2021).

Figure 19-3. Lithium Hydroxide Monohydrate price in $US - Historical and forecast from 2016-2027 (used with Permission from Global Lithium LLC)



Based upon the LHM pricing information shown in Figure 19-3, a price of US$14,500/tonne was selected as it was within the low and high scenarios and similar to JP Morgan Chase's estimate.

20 ENVIRONMENTAL STUDIES, PERMITTING AND SOCIAL OR COMMUNITY IMPACT

20.1 Introduction

Standard Lithium is proposing to build the SWA Project for LHM production by processing brine with naturally occurring lithium found in the Smackover Formation. Standard Lithium will process the brine to form lithium chloride solution and convert to LHM. In the proposed SWA Project, Standard Lithium will need to develop brine supply and brine injection wellfields. The brine supply wellfield and ancillary equipment will provide the CPF with brine while the other will be used to inject tail-brine (lithium-depleted brine) and associated process water back into the Smackover Formation. This section of the report will focus on the listed components of Section 20 of a PEA for a new Standard Lithium facility near Magnolia, Arkansas. These components are as follows:

- Environmental Considerations
- Permitting Overview
- Operating Permits
- Title V Air Permits
- National Pollutant Discharge Elimination System
- Underground Injection Control (UIC) Permits
- Resource Conservation and Recovery Act Subtitle C Treatment, Storage and Disposal Permit
- Social Impact
- Environmental Management and Closure Plan

20.2 Environmental Considerations

If federal funds are used on this project, an Environmental Assessment (EA), wetland delineation, floodplain study and a cultural resource study would be required. Irrespective of whether federal funding is used or not, the proposed project will require multiple permits for air, water, hazardous waste, resource extraction, and underground injection. Permit application approvals in some cases will take more than a year from submission dates. Planning for the permits will need to take place with this long approval time in mind. Detailed plans will be needed so that the permit application process can be completed in a timely fashion.

20.3 Permitting

20.3.1 Overview

The SWA Project will require permits to be completed prior to construction of the facility. The permits will require review and approval from the Arkansas Department of Energy and Environment and potentially, the Environmental Protection Agency. The Arkansas Department of Energy and Environment is the permitting agency for both the environmental permits and resource extraction for the facility. The Department of Energy and Environment, Division of Environmental Quality (DEQ) oversees the air, National Pollutant Discharge Elimination System (NPDES), Resource Conservation and Recovery Act (RCRA) permits and underground injection control (UIC) permits. The Arkansas Oil and Gas Commission (AOGC) is the permitting authority for the brine resource.

20.3.2 Air Emissions Permitting

An air emissions permit will be required prior to the commencement of construction. The permit could take up to six months for approval. The permit will be for both the construction phase of the project and the operation of the CPF. There are three levels of air permits available under the DEQ air permitting program. The level of permit is directly tied to the mass of emissions the plant will produce. Calculations will need to be performed to determine the emissions rates. The calculations will take into consideration the production throughput, chemical reactions, and type of air emission controls used at the facility. A Title V permit is the middle tier permit and approval takes approximately six months after the permit application is submitted. Again, permit approval must be obtained prior to any changes or construction of new equipment can take place.

20.3.3 NPDES Permitting

There are seven NPDES water permits, authorized by DEQ, that are potentially applicable to the SWA Project. These permits include:

- Construction Stormwater
- NPDES Construction (Wastewater Treatment System)
- NPDES Individual (Process Water)
- Industrial General Stormwater
- Cooling Tower Water
- No Discharge (holding ponds)
- Underground Injection Wells

The NPDES construction permit authorizes the facility to build the wastewater treatment system. All but two of the permits will have a public comment period and may require a public meeting depending upon comments received. These permits are required to be in place prior to construction of a new facility or the piece of the facility each one covers.

20.3.4 Underground Injection Control (UIC) Permitting

DEQ and AOGC are the permitting authorities for the non-hazardous and hazardous injection wells. The AOGC permit will be required for the Class V spent brine injection well(s). The UIC permitting process is a multiple-step process. An initial permit application is the first step in that process. Once the permit application has been approved by DEQ, then a drilling plan will need to be submitted. After the drilling plan is approved, the wells can be drilled. DEQ will be in communication on the progress of the wells being drilled. DEQ staff will also likely be onsite during the well drilling. Testing of the new wells will then be required. A drilling report, including test results, will then need to be submitted to DEQ. If the well is a hazardous waste injection well, a No Migration Petition must be sent to EPA after DEQ approves the drilling report. The well can go into operation after the No Migration Petition is approved by EPA. This process could take anywhere between two and five years. At this time, there are no hazardous waste wells contemplated or required for the SWA Project.

20.3.5 Resource Conservation Recovery Act

If a Class I hazardous waste injection well is need for the project, it will need to be permitted through the Resource Conservation Recovery Act (RCRA) program at DEQ. The RCRA permit would also apply to the treatment and storage of any hazardous waste generated onsite. The RCRA permit approval process would take approximately 18 months once the permit application is submitted to DEQ. It is possible to get a RCRA permit for the storage and operation of RCRA portions of the facility, and then modify the permit to add an injection well at a later date.

20.3.6 Construction Permits, Approvals, and Plans

Permits will need to be in place prior to construction of the new CPF. DEQ uses a one permit system for air emissions permitting. The air permit must be approved prior to construction of the facility. The air permit will also cover the facility during start-up and while operating. The water discharge permits will also need to be approved prior to construction. There are two NPDES construction permits. The first is the general stormwater discharge permit that is required for the construction phase of the project. The second is the NPDES construction permit, which authorizes the construction of the wastewater treatment system. The NPDES individual permit (process water), no discharge permit (if needed) approval is also required prior to construction. The industrial stormwater permit is required prior operation of the facility. The RCRA permit or at least portions of the permit, will also need to be approved prior to construction. The time it takes for DEQ to approve these permits varies from six months to more than a year. The UIC program will take the longest from application to approval. A list of permits and approximate approval times is listed below in Table 20-1.

Table 20-1. Permit approval estimated timelines

Permit	Approximate Approval Time
Title V Air Permit	12 Months
Minor Source Permit	6 Months
NPDES Construction Permit (Wastewater Treatment System)	12 Months
Stormwater Construction Permit	1 Month
NPDES Individual (Process Water)	18 months
No Discharge Permit (holding ponds)	18 Months
Industrial General Stormwater Permit (Approval Prior to Startup)	3 Months
Cooling Tower Water	1 Month
RCRA Permit (Hazardous Waste)	18 Months
UIC Program Approval	2-5 years

Detailed plans of the new facilities will need to be developed prior to permitting. The plans will be used in all of the permitting applications. Each permit will require its own permitting package and drawings. The lead time allowed for permitting also needs to account for the time it takes to prepare the permit application packages.

20.4 Social Impact

A formal social impact study has not been completed for this project. It is likely that public meetings will be required as a part of the overall permitting process. The region around the proposed facility is a rural portion of a rural state. There is an opportunity for a positive social impact on the surrounding communities. The community will benefit from the construction phase because the project will require skilled labor to complete. The community will also benefit with the additional opportunities for a labor market skilled in similar operations once the facility has been constructed.

20.5 Environmental Management and Closure Plan

Standard Lithium may want to develop an environmental management plan for the proposed SWA Project but it is not required by any of the regulatory agencies. A closure plan will be required as a part of the hazardous waste permit. The closure plan will need to detail the process of shutting down the facility to prevent any negative environmental impacts after operations cease. The closure plan will also need to minimize the amount of maintenance the facility will require after closure. The closure plan will need to be accompanied by a cost estimate to execute the closure plan. Standard Lithium will be required to provide financial assurance that the closure plan can be implemented in case the facility shuts down.

21 CAPITAL AND OPERATING EXPENDITURE COSTS

The capital expenditure (CAPEX) cost estimate and operating expenditure (OPEX) cost estimate were prepared under the general provisions for a Class 5 Estimate, as defined in the American Association of Cost Engineers (AACE) International Recommended Practice No. 18R-97 Cost Estimate Classification System as Applied in Engineering, Procurement, And Construction for The Process Industries. The AACE classification system uses a 1 to 5 scale, where a “Class 1 Estimate” is the most accurate and a “Class 5 Estimate” is the least accurate.

An AACE Class 5 estimate is used for preliminary comparison of alternatives and generally describes a hypothetical installation. The estimate is suitable to identify potential fatal flaws and identify the work that needs to be done at further stages of a project, leading to positive acceptance of a project.

The accuracy of this estimate has been determined to be -30%/+50%. While a contingency of 35% is typical for estimates of this range, the level of design completed to date is greater than is typical at this stage of development. Therefore, a less conservative contingency of 25% has been included.

21.1 Capital Expenditure Cost Estimate –

21.1.1 Basis of Estimate

The basis of estimate (BOE) for the CAPEX is a work breakdown of the project’s individual components. These components and the basis for their specific areas are broken down and further described below.

21.1.1.1 General

- Project execution includes the construction of one (1) commercial scale production facility and the necessary brine production gathering and injection facilities.
- Design is for a facility that produces battery grade (>99.4% pure) LHM product.
- LHM production by the facility is based on an average brine grade of 399 mg/L of lithium.
- Equipment size and related cost were developed based on an hourly production rate of 3.833 tonnes per hour of LHM.
- Estimated costs are based on current North American pricing from established cost databases and budget quotations from selected vendors and contractors.
- An exchange rate of 1 US$ = 1.2436 CAD (Canadian Dollar) was used to convert CAD provided costs to US currency (US$).

21.1.1.2 Brine Supply & Injection Wellfields

- Brine gathering system consisting of five (5) well pad facilities that will be comprised (as a whole) of four (4) vertical wells, fourteen (14) directional wells, and five (5) horizontal wells.
- Capital cost estimates for the wells were completed by HGA in cooperation with Baker Hughes and other drilling service suppliers. The drilling cost estimates are based on the conceptual brine supply and injection wellfields design provided by Matrix Solutions. Well pad locations and drilling methodologies were identified based on down hole performance requirements and location/proximity factors. A

"typical" drilling plan model was established and priced for the three (3) drilling methods detailed below:
- Vertical Well
- Directional Well
- Horizontal Well

- The well sites are expected to be drilled on a continuous schedule from start to finish. This is expected to accrue certain cost savings for reduced mobilization costs, overhead, etc. over the course of this effort. A "Drilling Efficiencies Factor" of 5% has been included in the wellfield cost for the variable (daily) drilling expenses to account for these anticipated cost savings.
- Cost estimates for the electrical submersible pumps (ESP) are based on an 800 horsepower, high flow rate pump, with a cost of US$ 332,000 per pump including all accessories. ESP sizing is based on historical pump sizing for similar wells in the region. The pump sizing and costs are subject to change depending on the requirements set forth in the final wellfield design. Further analysis should be conducted to better define the pump sizing requirements for the wellfield as the costs for these pumps vary significantly with size.
- Cost estimates associated with surface facilities equipment at each facility are based on historical pricing for installation and budgetary equipment costs in Aspen In-Plant Cost Estimator Software™, Version 12.
- Costs associated with the site preparation and auxiliary infrastructure to be installed at each well pad facility are based on budgetary contractor estimates. A material factor of 0.088 and labor factor of 0.072 was used to estimate the cost for electrical work at the facility.
- Indirect Costs are factored at 15% of Direct Cost to account for Owner's Engineering and other miscellaneous costs.

21.1.1.3 Brine Supply/Return and Sour Gas Pipeline Network

- Sour gas will be separated from the brine at the supply well facilities and delivered to the production facility in pipelines alongside the brine feedstock.
- Anticipated brine feedstock flow to the production facility is approximately 1,800 m^3/hour.
- Pipeline cost estimates are based on material quotes received from suppliers – detailed below in Table 21-1 along with installation and land costs from previous projects.

Table 21-1. Pipeline material summary

Service	Size	Type / Specification	Quantity
Brine Supply Pipelines	25.40cm to 50.80cm (10" to 20")	NOV Green Thread HP25 Fiberglass	18.36 km (11.41 miles)
Barren Brine (Injection) Pipelines	30.48cm to 60.96cm (12" to 24")	NOV Green Thread HP25 Fiberglass	20.13 km (12.51 miles)
Sour Gas Pipelines	15.24cm to 40.64cm (6" to 16")	SDR-11/PE3408 HDPE	18.36 km (11.41 miles)
Total	-	-	56.86 km (35.33 miles)

- Survey and land costs were estimated based on budgetary pricing developed by HGA.
- Installation and environmental services were also based on budgetary pricing from local companies familiar with executing this type of work.
- Indirect cost estimates, such as those for engineering and inspection, are based on similar sized projects.

21.1.1.4 Central Processing Facility

- The CPF includes the following processing units/areas.
  - Brine receiving unit for degassing, solids removal, and storage of pre-treated brine prior to its introduction into Process Train 1.
  - Sour gas receiving and disposal unit to receive sour gas from the brine supply well system and the degassing system in the brine receiving area. Sour gas is expected to be metered and delivered to a nearby Mission Creek sour gas gathering pipeline feeding the Mission Creek Dorcheat Gas Plant.
  - LiSTR unit produces a lithium chloride (LiCl) as a purified and concentrated solution feedstock for the LHM unit.
  - LHM Unit producing an average of 30,000 tonnes per year of LHM.
  - Annual production is based on approximately 333 days of operation per year or 8,000 hours.
  - Shipping and receiving unit for the storage and truck loading of the finished LHM.
  - Utilities unit to produce:
    - 18,144 kg/hr (40,000 lb./hr) of medium pressure steam
    - 10 m^3/min (2,700 gal/min) of raw water
    - 106 m^3/min (28,000 gal/min) of cooling water
    - 0.3 m^3/min (80 gal/min) of demineralized water
    - 0.3 m^3/min (80 gal/min) of RO-filtered water
    - 45 m^3/min (1,600 ft^3/min) of compressed air
- Lang Factors were used as the primary method to estimate the cost for the inside boundary limit (ISBL) areas of the production facility. The Lang Factor is one of the factored estimating techniques recommended by AACE International for Class 4 and Class 5 estimates. This method uses a formula that contains a set of factors multiplied by the total equipment cost (TEC) to obtain the total plant cost (TPC).

- Gross production schedules were estimated to form the basis of nominal process facilities capacity, using assumed flow sheets and process requirements.
- Equipment lists were prepared based on preliminary process flow diagrams (PFDs) and are priced based on historical pricing, informal vendor pricing, and formal budgetary pricing for the major pieces of equipment at the facility.
- AACE percentage factors (Table 21-2) were applied to equipment costs to estimate installation costs. Much of the equipment will either be packaged or require very little auxiliary equipment support. Vendor pricing was obtained for most of the major equipment associated with this project. The AACE factors have been refined accordingly to reflect the actual process conditions

Table 21-2. Lang Factors comparison between factors used in the Technical Report and AACE 59R-10 (2011)

Description	AACE 59R-10-2011 Lang Factor % Values for Fluid Processing	PEA Average Factor % Values	Delta + / (-)
Direct Costs			
Purchased Equipment Cost	100	100	-
Equipment Setting	4	1.53	(2.47)
Site Development	5	4.55	(0.45)
Concrete	8	8.90	0.90
Structural Steel	13	5.41	(7.59)
Buildings	2	1.65	(0.35)
Piping	97	26.23	(70.77)
I&C	42	12.36	(29.64)
Electrical	16	8.05	(7.95)
Insulation	7	2.86	(4.14)
Painting	6	1.59	(4.41)
Total Direct Plant Cost	300	173.13	(126.87)
Indirect Costs			
Labor Indirect & Field Costs	72	51.05	(20.95)
Contractor Engineering Fees	91	35.84	(55.16)
Owner's Engineering & Oversight	42	32.54	(9.46)
Total Indirect Cost	205	119.43	(85.57)
Total Installed Cost (TIC)	505	292.56	(212.44)

21.1.2 Capital Expenditure Cost Estimate

The total capital cost for the project is detailed below in Table 21-3.

Table 21-3. SWA Project capital expenditure cost estimate

Description		Equipment Cost US$	Factor % Values	Factored Cost US$
Well-Field				
-	Supply Wells & Facilities	Included	N/A	$123,290,000
-	Injection Wells & Facilities	Included	N/A	$83,854,000
Pipelines				
-	Brine Supply Pipelines	Included	N/A	$14,770,000
-	Brine Injection Pipelines	Included	N/A	$20,497,000
-	Sour Gas Pipelines	Included	N/A	$5,942,000
Brine Receiving/Pre-Treatment				
-	Brine Receiving	$4,415,000	426%	$18,808,000
-	Raw Brine Storage	$3,159,000	267%	$8,433,000
-	Brine Solids Removal	$10,333,000	351%	$36,300,000
LiSTR Unit				
-	Sorbent Loading	$21,100,000	365%	$77,116,000
-	Loaded Sorbent Washing	$16,978,000	304%	$51,687,000
-	Sorbent Stripping	$2,819,000	354%	$9,974,000
-	SAC/WAC IX	$2,118,000	384%	$8,133,000
-	Stripping Sorbent Washing	$19,053,000	306%	$58,291,000
-	UHPRO	$13,739,000	244%	$33,525,000
LHM Unit				
-	Brine Treatment (Chemical/IX)	$1,660,000	209%	$3,476,000
-	MP Brine Storage	$349,000	267%	$931,000
-	NaCl Crystallization	$9,382,000	297%	$27,823,000
-	Ultra-Pure Brine Storage	$100,000	336%	$335,000
-	Electrolysis	$34,739,000	207%	$71,788,000
-	Evaporation Crystallization	$12,270,000	210%	$25,706,000
-	Product Bagging Facility	$50,000	210%	$105,000
-	Vent Scrubber & Spill System	$1,528,000	126%	$1,919,000
-	Debromination Unit	$390,000	210%	$817,000
Utilities/Infrastructure				
-	Utilities Equipment	$10,500,000	375%	$39,406,000
-	Chemical Receiving, Storage & Distribution	$2,748,000	385%	$10,589,000
-	Plant Buildings			$3,452,000
-	Infrastructure			$1,013,000
-	Wastewater Collection, Treatment & Disposal	$253,000	386%	$974,000
Contingency (Based on Total Equipment Cost of 25%)		Included	N/A	$132,969,000
TOTAL FACTORED COST				$869,867,000

21.2 Operating Expenditure Cost Estimate

21.2.1 Basis of Estimate

The BOE for the OPEX of the SWA Project is a breakdown of the project's individual operating expenditures. The operating costs presented herein are for full production (30,666 tonnes per year LHM) after completion of the project for the first 15 years of operation with a reduced production rate of 28,000 tonnes per year for the remaining 5 years of operation averaging to 30,000 tonnes per year over the 20-year life of the SWA Project.

21.2.2 Direct Operational Expenditures

The following cost elements are taken into account for the direct OPEX estimation.

21.2.2.1 Manpower

Labor manning levels are based on experience and reported data from facilities operating in the region. Salary and wage estimates are based on published data for various trades prevailing in the City of El Dorado, Arkansas. This is the closest significant population center to Magnolia, Arkansas, where the SWA Project will be located. Personnel and staffing requirements, for the different parts of the operation, are discussed in the following sections.

21.2.2.1.1. Facility Management

Management includes the higher-level managerial positions required for supervision of the operation of the CPF and the supporting wellfield facilities, as summarized below in Table 21-4. Management personnel will not be assigned to a shift system and will be paid based on a standard 5 day/40 hour per week work schedule.

Table 21-4. Management personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Plant Manager	1	1	$180,000	$180,000
Assistant Plant Manager	1	1	$100,000	$100,000
Senior Plant Engineer	1	1	$160,000	$160,000
Maintenance Manager	1	1	$95,000	$95,000
Health, Safety & Environmental Manager	1	1	$120,000	$120,000
Logistics Manager	1	1	$95,000	$95,000
Total	6	-	$125,000	$750,000

21.2.2.1.2. Administration Personnel

Administrative personnel include the support positions required for the "front office" operation of the CPF, as summarized below in Table 21-5. Administrative personnel will not be assigned to a shift system and will be paid based on a standard 5 day/40 hour per week work schedule.

Table 21-5. Administrative personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Accounting Specialist	1	1	$80,000	$80,000
Receptionist/Data Clerk	1	1	$45,000	$45,000
Total	2	-	$62,500	$125,000

21.2.2.1.3. Security Personnel

Security personnel include the support positions required to ensure a secured facility and work environment for both the personnel and end product, as summarized below in Table 21-6. Security personnel will be assigned to a 12-hour DuPont rotating shift pattern with 24 hours per day/7 days per week work schedule.

Table 21-6. Security personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Security Specialists	8	2	$55,000	$440,000
Total	8	-	$55,000	$440,000

21.2.2.1.4. Production Personnel

Production personnel include the staff required for operation of the wellfield and CPF, as shown in Table 21-7. Plant engineers will not be assigned to a shift system and will be paid based on a standard 5 day/40 hour per week work schedule. Plant foreman and operators will be assigned to a 12-hour DuPont rotating shift pattern with 24 hours per day/7 days per week work schedule.

Table 21-7. Production personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Plant Engineer(s) - Process/Mechanical	1	1	$95,000	$95,000
Plant Engineer(s) - Electrical/ Instrumentation	1	1	$95,000	$95,000
Plant Foreman(s) - All Areas	4	2	$85,000	$340,000
Plant Operator(s) - All Areas	36	2	$75,000	$2,700,000
Total	42	-	$76,905	$3,230,000

21.2.2.1.5. Shipping & Receiving Personnel

Shipping and receiving personnel will not be assigned to a shift system and will be paid based on a standard 5 day/40 hour per week work schedule, as shown below in Table 21-8.

Table 21-8. Shipping & receiving personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Shipping & Receiving Clerks	1	1	$75,000	$75,000
Logistics/Loading Operators	1	1	$45,000	$45,000
Total	2	-	$60,000	$120,000

21.2.2.1.6. Maintenance Personnel

Maintenance personnel positions will be assigned on both a standard work week schedule (5 day/40 hour per week) and a 12-hour DuPont rotating shift pattern (24 hours per day/7 days per week), as detailed below in Table 21-9.

Table 21-9. Maintenance personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Mechanics – Day Shift	2	1	$75,000	$150,000
Mechanics – Rotating Shift	4	2	$75,000	$300,000
Electrical/Instrument Tech – Day Shift	2	1	$75,000	$150,000
Electrical/Instrument Tech – Rotating Shift	4	2	$75,000	$300,000
Total	12	-	$75,000	$900,000

21.2.2.1.7. Quality Control & Laboratory Personnel

Quality Control (QC) and laboratory personnel will not be assigned to a shift system and will be paid based on a standard 5 day/40 hour per week work schedule, as shown below in Table 21-10.

Table 21-10. Quality control and laboratory personnel

Position	Full Time Employees (FTE)	Shifts	Average Annual Salary US$	Total Annual Cost US$
Lab Technician	1	1	$85,000	$85,000
Lab Assistant	1	1	$60,000	$60,000
Total	2	-	$72,500	$145,000

21.2.2.1.8. Manpower Summary

A cost summary of manpower in all categories is provided below in Table 21-11.

Table 21-11. Manpower cost summary

Category	Full Time Employees (FTE)	Average Annual Salary US$	Total Annual Cost US$
Management Personnel	6	$125,000	$750,000
Administration Personnel	2	$62,500	$125,000
Security Personnel	8	$55,000	$440,000
Production Personnel	42	$76,905	$3,230,000
Shipping & Receiving Personnel	2	$60,000	$120,000
Maintenance Personnel	12	$75,000	$900,000
QC & Lab Personnel	2	$72,500	$145,000
Total	74	$77,162	$5,710,000

21.2.2.2 Electrical Power

Electrical energy will be delivered to the sites from the Entergy Arkansas power grid. The electrical costs are based on the latest Entergy rate sheet for large power service (LPS) as detailed below in Table 21-12.

Table 21-12. Entergy large power service rate sheet

Description	Unit	Base Case Value (US$)
Customer Charge	$ per Month	$468.60
Demand Charge		
- Summer (June - Sept)	$ per kW	$13.42
- Other	$ per kW	$11.28
Energy Charge		
- Summer (June - Sept)	$ per kWh	$0.03
- Other	$ per kWh	$0.02

The electrical energy cost is summarized below in Table 21-13.

Table 21-13. Electrical use and cost

Description	Quantity	Unit	Average Annual Cost US$*
Wellfield			
Customer Charge	12	Month	$5,623
Demand Charge			
- Summer Months (June - Sept)	59,739	kW	$801,702
- Remaining Months	119,479	kW	$1,347,720
Energy Charge			
- Summer Months (June - Sept)	43,126,807	kWh	$1,168,305
- Remaining Months	86,253,614	kWh	$1,662,107
Sub-Total			$4,985,457
Central Processing Facility			
Customer Charge	12	Month	$5,623
Demand Charge			
- Summer Months (June - Sept)	79,899	kW	$1,072,245
- Remaining Months	159,798	kW	$1,802,521
Energy Charge			
- Summer Months (June - Sept)	53,052,726	kWh	$1,437,198
- Remaining Months	106,105,452	kWh	$2,044,652
Sub-Total			$6,362,240
Grand Total			**$11,347,697**

* Annual consumption and cost figures are based on an average annual LHM production rate of 30,000 tonnes.

21.2.2.3 Reagents and Consumables

Reagents and consumables are the various additions required for the production process of LHM.

Quantities for each item are estimated based on preliminary process flow calculations for the plant. The costs for the reagents and chemicals are based on pricing received from local suppliers as shown below in Table 21-14.

Table 21-14. Average annual reagents cost for 30,000 tonnes LHM per year production

Description	Average Annual Consumption*	Unit Cost US$	Average Annual Cost US$*
Wellfield			
Scale Inhibitors	11.9 m^3	\$12,728 / m^3	\$151,756
Corrosion Inhibitors	7.35 m^3	\$19,905 / m^3	\$146,263
Sub-Total	-	-	\$298,019
Central Processing Facility			
CO_2 Free Air	151,560.66 kg	\$0.13 / kg	\$19,703
Hydrochloric Acid - 31.5%			
- Consumption at CPF	156,612,483 kg	\$0.13 / kg	\$20,845,122
- Production at Synthesis Plant	(79,674,446) kg	\$0.13 / kg	(\$10,604,669)
Lithium Titanate	248 tonnes	Credit from entrained Lithium is greater than the \$8,000/tonne unit cost for Lithium Titanate **	\$0
Sodium Chloride			\$0 (No revenue recognized as surplus NaCl will not be marketed for sale)
- Consumption at CPF	2,350,684 kg	\$0.51 / kg	\$1,198,849
- Production at NaCl Crystallizer	(20,727,584) kg	\$0.51 / kg	(\$10,571,068)
Sodium Hydroxide - 50%	4,897,895 kg	\$0.55 / kg	\$2,670,822
Ammonium Hydroxide - 19%	136,738 tonnes	\$56.75 / tonne	\$7,759,863
Nitrogen	494,712 Nm^3	\$0.35 / Nm^3	\$171,980
Membrane Replacement	27767 m^2	\$70.00 / m^2	\$1,943,667
Sub-Total	-	-	\$24,789,510
Grand Total	-	-	\$25,087,529

* Annual consumption and cost figures are based on an average annual LHM production rate of 30,000 tonnes.
** The lithium contained in the lithium titanate nominally increases in value when converted to battery grade LHM; however, there is no credit assigned in the OPEX. The sorbent pricing is based upon the material costs only. Similar materials are currently manufactured in China for use in older lithium-ion battery architectures. Domestic sorbent pricing at a commercial scale will be evaluated for future project studies (i.e. Pre-feasibility study).

21.2.2.4 Water

Water wells will be installed at each of the well facilities and CPF. Operating costs for the wells are included in the electrical power and maintenance & servicing portions of this OPEX breakdown.

21.2.2.5 Natural Gas

Natural gas will be required as fuel gas for the 18,140 kg/hr (40,000 lb/hr) boiler at the CPF, as detailed below in Table 21-15.

Table 21-15. Natural gas use

Description	Annual Natural Gas Use (MMBtu)*	Unit Cost US$ / MMBtu	Average Annual Cost US$*
Natural gas for steam production	376,471	$3.144	$1,183,624
Total	-	-	$1,183,624

* Annual consumption and cost figures are based on an average annual LHM production rate of 30,000 tonnes.

The estimated cost of natural gas is based on the supply from an on-site existing distribution network. The unit cost rate of natural gas used is for large industrial users in Arkansas. No credit is provided for any natural gas that may be co-produced with the brine.

21.2.2.6 Maintenance & Servicing

21.2.2.6.1. Well Facilities

Several routine maintenance and servicing activities are required for efficient operation of the supply and reinjection well facilities, as detailed below in Table 21-16.

Table 21-16. Well facilities maintenance & servicing

Description	Basis	Unit Cost US$	Average Annual Cost US$
ESP Servicing/ Workovers	1 per Supply Well every 2 Years	$30,000	$345,000
ESP Replacements	2-Year Service Life for ESP's	$362,000 per ESP w/Installation	$4,163,000
Surface Eqmt/Site Servicing	3% Direct Cost Less Drilling & Equipment Costs	$1,806,246	$1,806,246
Total	-	-	6,314,246

The estimated cost for these activities is based on historical pricing and factors used on similar well facilities in south Arkansas.

21.2.2.6.2. Pipelines

Routine maintenance activities for the pipeline Right-of-Way (ROW) are provided below in Table 21-17. These costs do not include major pipeline overhauls or repairs as the service life for the pipelines are expected to be greater than the service life of the project.

Table 21-17. Pipelines ROW maintenance & servicing

Description	Basis	Unit Cost US$	Average Annual Cost US$
Pipelines ROW	3% of Direct Cost	$1,236,289	$1,236,289
Total	-	-	$1,236,289

21.2.2.6.3. Central Processing Facility

Routine maintenance activities for the CPF are provided below in Table 21-18. A 4% factor was used to estimate the maintenance and servicing costs for much of the CPF. A $1,600,000 refurbishment cost was included per year to service the Electrolysis Cellhouse. A 3% factor was used to estimate the general maintenance costs associated with the site/infrastructure upkeep at the facility.

Table 21-18. CPF Maintenance & Servicing Costs

Description	Basis / Frequency	Average Annual Cost US$
Receiving/Pre-Treatment	4% Equipment Costs	$716,278
LiSTR Unit	4% Equipment Costs	$3,032,295
LHM Unit		
- General	4% Equipment Costs	$2,418,650
- Electrolysis Cellhouse Servicing/Workover	Once a Year	$1,600,000
Utilities	4% Equipment Costs	$540,051
Site/Infrastructure	3% Equipment Costs	$107,161
Total	-	$8,414,435

21.2.2.7 Product Transport

All reagent pricing includes transportation to site. Additionally, the cost of freight for LHM has been assumed to be included in purchaser contracts.

21.2.2.8 Solids Disposal

It is assumed that two pump-outs will be required annually to remove the solids from the three-phase separators on each of the supply wells, as shown below in Table 21-19. The cost per pump out is based on historical pricing for a pump truck.

Table 21-19. Solids disposal

Process Area	Total Annual Pump Outs	Cost US$ per Pump Out	Total Annual Cost US$	Remarks
Brine Supply Well Separators	46	$1,500.00	$34,500.00	2 pump outs per year for 23 separators.
Total	46	-	$34,500.00	

21.2.2.9 Miscellaneous Costs

Miscellaneous operating costs include costs that may be required but cannot be detailed at this stage of the project. For these reasons, these costs are estimated at 1.5% of the other direct costs as detailed in Table 21-20.

Table 21-20. Miscellaneous direct operational costs

Description	Unit	Total Amount
Direct Operational Costs	US$	59,328,319
Cost as a Percentage of Direct Operational Costs	%	1.50
Total	US$	889,925

21.2.3 Indirect Operational Expenditures

The following indirect cost elements are included for the OPEX estimation:

21.2.3.1 Insurance

Insurance during the operation phase will cover property, general liability, and risk of business interruption. The annual insurance premium has been estimated at 0.5% of direct CAPEX or $2,659,377.

21.2.3.2 Sales, Marketing, & Customers Relations

The annual cost of sales, marketing, and customer relations is estimated at 0.15% of direct OPEX or $90,327.

21.2.3.3 Plant Optimizations & Development

The annual cost for plant optimization and project development is estimated at 0.25% of direct OPEX or $150,546 to cover salaries for consultants and contractors for studies on development tasks.

21.2.3.4 Environmental Monitoring

Environmental monitoring contains the annual cost of environmental assessment and monitoring including air emissions, water discharges, waste disposal, noise emission, and changes to the environment. The annual cost for environmental monitoring is estimated at 0.5% of direct OPEX or $301,091.

21.2.3.5 Community Benefits

The annual cost for community benefits is estimated at 0.01 % of direct OPEX or $6,022.

21.2.3.6 Mine Closure Fund

Each well will need to be plugged and capped at the end of operations. A $35,000 allowance has been included for each brine supply and injection well to cover the cost to plug and cap the wells. These costs will be incurred as a one-time cost at the end of operations. A surety bond will be secured prior to operation of the plant to provide the necessary assurances that the mine closure funds will be available at or prior to the conclusion of operations of the facilities. The surety bond principal is assumed to be a one-time 3% fee of the total closure fund amount payable on the 1st year of operations of the plant.

21.2.4 Royalties & Land Fees

The following cost elements are taken into account for the royalties and land costs:

21.2.4.1 Royalty Fees

On January 8th, 2018, Standard Lithium executed an Option Agreement with TETRA Technologies Inc. (TETRA) to acquire the rights to conduct exploration, production, and lithium extraction activities on up to 33,000 acres of brine leases in southern Arkansas, USA. The terms of this agreement are detailed below and summarized in Table 21-21.

- Under the terms of the Option Agreement with TETRA, Standard Lithium will be granted the rights in consideration for a series of cash payments, as well as certain ongoing royalties tied to Lithium production from the properties. In consideration of the execution of the Option Agreement, the Company has made a non-refundable cash payment to TETRA of US$500,000, with further cash payments owing to TETRA as follows:
  - US$500,000 on or before the date that is thirty (30) calendar days following the Agreement Date.
  - An additional US$600,000 on or before the date which is twelve (12) months following the Agreement Date.
  - An additional US$700,000 on or before the date which is twenty-four (24) months following the Agreement Date.
  - An additional US$750,000 on or before the date which is thirty-six (36) months following the Agreement Date.
  - An additional annual payment of US$1,000,000 on or before each annual anniversary of the Agreement Date, beginning with the date that is forty-eight (48) months following the Agreement Date, until the earlier of the expiration of the 10-year exploratory period or, if the Company exercises the Option, the Company begins payment of the Royalty.
- Upon commercial production, the Company will pay TETRA a two and one-half percent (2.5%) royalty on gross revenue derived from the sale of lithium produced from the properties, subject to a minimum annual royalty payment of US$1,000,000.

Table 21-21. TETRA brine lease agreement summary

Description	Total Amount US$	Remarks
Initial Payment	$500,000	Paid Prior to Year 1 (2021) of Project.
- 30 Day Payment after Agreement	$500,000	
- 12 Month Payment after Agreement	$600,000	
- 24 Month Payment after Agreement	$700,000	
- 36 Month Payment after Agreement	$750,000	
- 48 Month Payment after Agreement	$1,000,000	
Royalties		
- Initial US$1M Annual Payments	$4,000,000	During Project Development & Startup
- Royalties – 2.5% of Gross Revenue	$285,038,045	Total Amount Paid for Life of Plant

Does not include future lease-fees-in-lieu-of-royalties which are still to be determined and subject to regulatory approval (lease-fees-in-lieu-of-royalties have been determined for bromine and certain other minerals in the State of Arkansas, but have not yet been determined for lithium extraction). Additional items will be identified and addressed in future stages of development for the project.

21.2.4.2 Land Costs

21.2.4.2.1. Well Facilities and Central Processing Plant

The brine supply and injection well facilities will require approximately 167 acres of surface area for the facility arrangements detailed in Sections 18.1.1 and 18.3.1. No financing fees are included in the assessment at this time for the land costs associated with the well facilities.

The CPF will be located on the 57 acre “Mission Creek” property described in Section 18.2. It is assumed that this land will be purchased between years 2 and 3 of the project, after preliminary engineering and property negotiations are complete. These costs have been included in the assessment based on an assumed purchase price of US$5,000 per acre plus 20% for property acquisition related fees (US$6,000 Total/Acre) as described below in Table 21-22.

Table 21-22. Well facilities and central processing plant land costs

Description	Quantity	Unit	Units Cost US$	Total Cost US$
Supply Well Facilities (5 @ 16.73 Acres Each)	83.62	Acres	$6,000	$501,739
Injection Well Facilities (5 @ 16.63 Acres Each)	83.16	Acres	$6,000	$498,967
Central Processing Facility	57.00	Acres	$6,000	$342,000
Total	223.78	Acres	-	$1,342,706

21.2.4.2.2. Pipeline Right-of-Way

Approximately 38 km (24 miles) of Right-of-Way (ROW) will be required for the pipelines detailed in Sections 18.1.2 and 18.3.2. It is assumed that the ROW's will be purchased between years 2 and 3 of the project, after preliminary engineering and property negotiations are complete. The assessment includes an average cost of $189,819 per km ($118,637 per mile) of ROW which includes the ROW and labor/acquisition related costs as described below in Table 21-23. No financing fees are included in the assessment at this time for the land costs associated with the well facilities.

Table 21-23. Pipeline right-of-way land costs

Description	Quantity	Unit	Units Cost US$	Total Cost US$
Brine Supply & Sour Gas Pipelines	11.41	Mile	$118,637	$1,353,835
Barren Brine (Injection) Pipelines	12.58	Mile	$118,637	$1,492,659
Total	23.99	Mile	-	$2,846,494

21.2.5 OPEX Summary

Annual operating cost summary is given in Table 21-24.

Table 21-24. Annual OPEX summary

Description	Total Average Annual Cost US$	Total Average Cost US$ per Tonne LHM
Direct Operational Expenditures		
- Manpower	$5,710,000	$190
- Electrical Power	$11,347,697	$378
- Reagents & Consumables	$25,087,529	$836
- Water	$0	$0
- Natural Gas	$1,183,624	$39
- Maintenance	$15,964,970	$532
- Solids Disposal	$34,500	$1
- Miscellaneous Costs	$889,925	$30
Sub-Total	$60,218,244	$2,007
Indirect Operational Expenditures		
- Insurance	$2,659,377	$89
- Sales Marketing & Customers Relations	$90,327	$3
- Plant Optimizations & Development	$150,546	$5
- Environmental Monitoring	$301,091	$10
- Community Benefits	$6,022	$0
- Mine Closure Fund	$84,718	$3
Sub-Total	$3,292,081	$110
Royalties & Land Fees		
- Royalties (per TETRA Contract)	$14,251,902	$475
- Land Costs (Total $ Divided by Life of Plant)	$209,460	$7
Sub-Total	**$14,461,362**	**$482**
Total	**$77,971,687**	**$2,599**

Note: All-in OPEX per one metric tonne of production is US$2,599.

22 Economic Analysis

This economic analysis for the SWA Project was prepared using a discounted cash flow economic model, showing both, pre- and post-tax results, to evaluate the project. CAPEX and OPEX expenditures presented in Section 21 have been used in this analysis. The model includes all taxes, government and commercial royalties/ payments, and community engagement contributions. The results include net present value (NPV) for an 8% discount rate, internal rate of return (IRR), and sensitivity analysis of key inputs.

The economic analysis for the SWA Project is preliminary in nature and includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves and there is no certainty that this economic analysis will be realized.

22.1 Evaluation Criteria

The following criteria have been used to develop the economic model:

- **CAPEX:** Capital investment for the 30,000 tonnes per year of battery grade LHM, including equipment, materials, indirect costs, and contingencies at 25%, is estimated to be US$869.97 Million. This total excludes interest expenses that might be capitalized during the same period.
- **OPEX:** The annual operating cost for the SWA Project is estimated at US$63.5 Million in 2021 (Direct Operational Expenditures escalated 2% annually). This figure includes manpower, electrical power, reagents and consumables, natural gas, maintenance, solids disposal, miscellaneous costs, insurance, sales and customers relations, plant optimizations and development, environmental monitoring, community benefits, and mine closure fund. Eighty percent (80%) of the OPEX costs are derived from three (3) of OPEX cost categories as shown below.
  - Reagents & Consumables – 40%
  - Maintenance – 25%
  - Electrical Power – 18%

  The remaining components of the operating costs have significantly lower impact on the overall economics.
- **Cash Flow:** Cash flow will reach 100% in 2025 after start of operations.
- **Construction:** Total construction time of the project starting first with the wellfield is estimated at 30 months (2.5 years). The construction time of the most significant cost item, the CPF, is estimated at 18 months (1.5 years).
- **Operating Life:** The plant is expected to operate for a period of no less than 20 years from the start of production.
- **Commodity Pricing:** Pricing for battery grade LHM is as per conclusions in Section 19 assumed at a price of US$14,500/tonne in 2021 with an annual escalation rate of 2% leading to an average price of US$19,068/tonne during the operating life of the SWA Project.
- **Discounted Cash Flow (DCF):** The DCF economic evaluation escalates the product price as well as the operating costs by 2% yearly in order to reflect inflation.
- **Equity Basis:** It has been assumed that 100% of capital expenditures, including pre-production expenses, are financed with Owners' equity for the purposes of the project DCF evaluation.

- **Pre-Construction Expenses:** Pre-construction expenses are treated as sunk costs and not included in the DCF analysis.

22.2 Taxes & Royalties

The following royalties and taxes have been applied to the economic analysis of the SWA Project.

22.2.1 Royalties and Lease Fees

Yearly royalty payments of 2.5% of gross revenue are considered which accumulates to royalty payments of US$285.0 Million over the 20 years of operating life. Additional fees for brine lease, land lease, and Rights of Ways accumulate to US$8.2 MM.

22.2.2 Depreciation

A yearly depreciation of 5% (facility evenly depreciated over 20 years of operating life) is used for this analysis.

22.2.3 Corporate Taxes

The US Federal Corporate Income Tax (CIT) rate of 21%, and the State Arkansas CIT rate of 5.9%, are used for this analysis.

22.3 CAPEX Spending Schedule

The economic model assumes that capital investment disbursements will be spread over 30 months (2.5 years).

Full production of LHM will start at the end of start-up and commissioning at a rate of 30,666 tonnes per year and will continue at that rate until year 15 of production when it is expected to decrease to 28,000 tonnes per year. This equates to an average LHM production of approximately 30,000 tonnes per year over the 20-year operating life of the SWA Project.

22.4 Production Revenues

Production revenues have been estimated based on the price scenario for a LHM product, as identified in Section 19.

22.5 Cash-Flow Projection

Table 22-1 summarizes the Discounted Cash Flow (DCF) for the assumed Base Case (Case 1) price and production level scenario.

Table 22-1. Annual operating cost summary

Economic Model

YEAR		2021	2022	2023	2024	2025	2026	2027	2028
Period		0	1	2	3	4	5	6	7
Total Months (Cumulative)		0	12	24	36	48	60	72	84
Engineering Duration (Months)	12	-	6	6	-	-	-	-	-
Construction Duration (Months)	18	-	-	6	12	-	-	-	-
Startup & Commissioning Duration (Months)	6	-	-	-	6	-	-	-	-
Inflation Factors									
LHM Cost	2.00%	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15
O&M Costs	2.00%	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15
Production (Tonnes per Year)									
LHM		-	-	-	-	30,666	30,666	30,666	30,666
Sale Price (USD $ per Tonne)									
LHM		-	-	-	-	15,695	16,009	16,329	16,656
Revenues (USD $)									
LHM		-	-	-	-	481,311,037	490,937,258	500,756,003	510,771,123
Gross Revenue (USD $)		**0**	**0**	**0**	**0**	**481,311,037**	**490,937,258**	**500,756,003**	**510,771,123**
Operating Expenses (USD $)									
Royalties & Lease Fees		1,000,000	1,000,000	5,189,200	1,000,000	12,032,776	12,273,431	12,518,900	12,769,278
Operating & Maintenance Costs		-	-	49,350	3,029,749	68,653,917	70,026,995	71,427,535	72,856,085
Operating Expenses		1,000,000	1,000,000	5,238,550	4,029,749	80,686,692	82,300,426	83,946,435	85,625,364
Operating EBITDA (USD $)		**(1,000,000)**	**(1,000,000)**	**(5,238,550)**	**(4,029,749)**	**400,624,344**	**408,636,831**	**416,809,568**	**425,145,759**
Taxable Expenses / Income (USD $)									
Development Capital Expenditure	(869,867,494)	-	(32,032,641)	(297,466,850)	(540,368,002)	-	-	-	-
Depreciation	5.00%	-	-	-	-	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)
Taxable Expenses		**-**	**(32,032,641)**	**(297,466,850)**	**(540,368,002)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**
Net Taxable Income		**(1,000,000)**	**(33,032,641)**	**(302,705,400)**	**(544,397,751)**	**357,130,970**	**365,143,457**	**373,316,193**	**381,652,385**
US Federal Corp. Income Tax	21.0%	-	-	-	-	(74,997,504)	(76,680,126)	(78,396,401)	(80,147,001)
State Arkansas Corp. Income Tax	5.9%	-	-	-	-	(21,070,727)	(21,543,464)	(22,025,655)	(22,517,491)
Profit after Taxes and Royalties		**(1,000,000)**	**(33,032,641)**	**(302,705,400)**	**(544,397,751)**	**261,062,739**	**266,919,867**	**272,894,137**	**278,987,893**
Net Cash Flow		**(1,000,000)**	**(33,032,641)**	**(302,705,400)**	**(544,397,751)**	**304,556,114**	**310,413,242**	**316,387,512**	**322,481,268**
Discounted Cash Flow (DCF) - Pre-Tax	8.00%	(1,000,000)	(30,585,779)	(259,521,090)	(432,160,487)	294,470,853	278,111,361	262,660,730	248,068,467
Discounted Cash Flow (DCF) - Post-Tax	8.00%	(1,000,000)	(30,585,779)	(259,521,090)	(432,160,487)	223,857,835	211,262,036	199,377,800	188,164,722
Cummulated DCF		(1,000,000)	(31,585,779)	(291,106,869)	(723,267,356)	(499,409,521)	(288,147,484)	(88,769,684)	99,395,039

YEAR	2029	2030	2031	2032	2033	2034	2035	2036	2037
Period	8	9	10	11	12	13	14	15	16
Total Months (Cumulative)	96	108	120	132	144	156	168	180	192
Engineering Duration (Months)	-	-	-	-	-	-	-	-	-
Construction Duration (Months)	-	-	-	-	-	-	-	-	-
Startup & Commissioning Duration (Months)	-	-	-	-	-	-	-	-	-
Inflation Factors									
LHM Cost	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37
O&M Costs	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37
Production (Tonnes per Year)									
LHM	30,666	30,666	30,666	30,666	30,666	30,666	30,666	30,666	30,666
Sale Price (USD $ per Tonne)									
LHM	16,989	17,329	17,675	18,029	18,390	18,757	19,132	19,515	19,905
Revenues (USD $)									
LHM	520,986,545	531,406,276	542,034,402	552,875,090	563,932,592	575,211,243	586,715,468	598,449,778	610,418,773
Gross Revenue (USD $)	**520,986,545**	**531,406,276**	**542,034,402**	**552,875,090**	**563,932,592**	**575,211,243**	**586,715,468**	**598,449,778**	**610,418,773**
Operating Expenses (USD $)									
Royalties & Lease Fees	13,024,664	13,285,157	13,550,860	13,821,877	14,098,315	14,380,281	14,667,887	14,961,244	15,260,469
Operating & Maintenance Costs	74,313,207	75,799,471	77,315,461	78,861,770	80,439,005	82,047,785	83,688,741	85,362,516	87,069,766
Operating Expenses	87,337,871	89,084,628	90,866,321	92,683,647	94,537,320	96,428,067	98,356,628	100,323,760	102,330,236
Operating EBITDA (USD $)	**433,648,675**	**442,321,648**	**451,168,081**	**460,191,443**	**469,395,271**	**478,783,177**	**488,358,840**	**498,126,017**	**508,088,538**
Taxable Expenses / Income (USD $)									
Development Capital Expenditure	-	-	-	-	-	-	-	-	-
Depreciation	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)
Taxable Expenses	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**
Net Taxable Income	**390,155,300**	**398,828,273**	**407,674,706**	**416,698,068**	**425,901,897**	**435,289,802**	**444,865,466**	**454,632,643**	**464,595,163**
US Federal Corp. Income Tax	(81,932,613)	(83,753,937)	(85,611,688)	(87,506,594)	(89,439,398)	(91,410,858)	(93,421,748)	(95,472,855)	(97,564,984)
State Arkansas Corp. Income Tax	(23,019,163)	(23,530,868)	(24,052,808)	(24,585,186)	(25,128,212)	(25,682,098)	(26,247,062)	(26,823,326)	(27,411,115)
Profit after Taxes and Royalties	**285,203,524**	**291,543,468**	**298,010,210**	**304,606,288**	**311,334,287**	**318,196,845**	**325,196,655**	**332,336,462**	**339,619,064**
Net Cash Flow	**328,696,899**	**335,036,843**	**341,503,585**	**348,099,662**	**354,827,661**	**361,690,220**	**368,690,030**	**375,829,836**	**383,112,439**
Discounted Cash Flow (DCF) - Pre-Tax	234,286,886	221,270,948	208,978,117	197,368,222	186,403,321	176,047,581	166,267,159	157,030,095	148,306,201
Discounted Cash Flow (DCF) - Post-Tax	177,584,707	167,601,834	158,182,237	149,293,979	140,906,946	132,992,743	125,524,592	118,477,238	111,826,869
Cummulated DCF	276,979,745	444,581,580	602,763,817	752,057,795	892,964,741	1,025,957,485	1,151,482,076	1,269,959,315	1,381,786,184

YEAR	2038	2039	2040	2041	2042	2043	2044	2045
Period	17	18	19	20	21	22	23	24
Total Months (Cumulative)	204	216	228	240	252	264	276	288
Engineering Duration (Months)	-	-	-	-	-	-	-	-
Construction Duration (Months)	-	-	-	-	-	-	-	-
Startup & Commissioning Duration (Months)	-	-	-	-	-	-	-	-
Inflation Factors								
LHM Cost	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.61
O&M Costs	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.61
Production (Tonnes per Year)								
LHM	30,666	30,666	28,000	28,000	28,000	28,000	28,000	-
Sale Price (USD $ per Tonne)								
LHM	20,304	20,710	21,124	21,546	21,977	22,417	22,865	-
Revenues (USD $)								
LHM	622,627,149	635,079,692	591,465,336	603,294,643	615,360,536	627,667,746	640,221,101	-
Gross Revenue (USD $)	**622,627,149**	**635,079,692**	**591,465,336**	**603,294,643**	**615,360,536**	**627,667,746**	**640,221,101**	**0**
Operating Expenses (USD $)								
Royalties & Lease Fees	15,565,679	15,876,992	14,786,633	15,082,366	15,384,013	15,691,694	16,005,528	-
Operating & Maintenance Costs	88,811,162	90,587,385	92,399,133	94,247,115	96,132,058	98,054,699	100,015,793	1,645,000
Operating Expenses	104,376,840	106,464,377	107,185,766	109,329,481	111,516,071	113,746,392	116,021,320	1,645,000
Operating EBITDA (USD $)	**518,250,308**	**528,615,315**	**484,279,570**	**493,965,161**	**503,844,465**	**513,921,354**	**524,199,781**	**(1,645,000)**
Taxable Expenses / Income (USD $)								
Development Capital Expenditure	-	-	-	-	-	-	-	-
Depreciation	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	(43,493,375)	-
Taxable Expenses	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**(43,493,375)**	**-**
Net Taxable Income	**474,756,934**	**485,121,940**	**440,786,195**	**450,471,787**	**460,351,090**	**470,427,979**	**480,706,406**	**(1,645,000)**
US Federal Corp. Income Tax	(99,698,956)	(101,875,607)	(92,565,101)	(94,599,075)	(96,673,729)	(98,789,876)	(100,948,345)	-
State Arkansas Corp. Income Tax	(28,010,659)	(28,622,194)	(26,006,386)	(26,577,835)	(27,160,714)	(27,755,251)	(28,361,678)	-
Profit after Taxes and Royalties	**347,047,319**	**354,624,138**	**322,214,709**	**329,294,876**	**336,516,647**	**343,882,853**	**351,396,383**	**(1,645,000)**
Net Cash Flow	**390,540,693**	**398,117,513**	**365,708,083**	**372,788,251**	**380,010,021**	**387,376,228**	**394,889,758**	**(1,645,000)**
Discounted Cash Flow (DCF) - Pre-Tax	140,066,967	132,285,469	112,213,419	105,979,340	100,091,599	94,530,954	89,279,235	(259,415)
Discounted Cash Flow (DCF) - Post-Tax	105,551,024	99,628,521	84,738,975	79,981,051	75,491,175	71,254,180	67,255,761	(259,415)
Cummulated DCF	1,487,337,207	1,586,965,728	1,671,704,703	1,751,685,754	1,827,176,929	1,898,431,109	1,965,686,870	1,965,427,455

Internal Rate of Return (IRR)	
Pre-Tax	40.516%
Post-Tax	32.045%

Net Present Value (NPV)	
NPV - Pre-Tax	$2,830,190,000
NPV - Post-Tax	$1,965,427,000

22.6 Economic Evaluation Results

The project economics resulting from the assumed price scenario at full production, which was used in the economic model, are presented in Table 22-2. Values of NPV were also calculated for a discount rate of 8%.

Table 22-2. Economic Evaluation – Case 1 (Base Case) Summary

Overview	Units	Values	Comments
Production	Tonnes / Year	30,666 to 28,000	Average annual production over the modelled life of the project is 30,000 TPA.
Plant Operation	Years	20	
Capital Cost (CAPEX)	US$	869,867,494	
Average Annual Operating Cost (OPEX)	US$	83,405,480	US$ 63,510,324 in 2021 (escalated by 2% annually).
Average Selling Price over the duration of the project	US$ / Tonne	19,068	US$ 14,500 in 2021 (escalated by 2% annually).
Average Annual Revenue	US$	570,076,090	2% LHM price inflation rate is included in the model revenue projections.
Discount Rate	%	8	
Net Present Value (NPV) Post-Tax	US$	1,965,427,000	
Net Present Value (NPV) Pre-Tax	US$	2,830,190,000	
Internal Rate of Return (IRR) Post-Tax	%	32.045	
Internal Rate of Return (IRR) Pre-Tax	%	40.516	

22.7 Sensitivity Analysis

A sensitivity analysis methodology, using one-factor-at-a-time (OAT), involves changing one input variable, keeping others at their baseline (nominal) values, and then returning the variable to its nominal value. This is repeated for each of the other inputs in the same way.

OAT sensitivity analysis of the project key variables (CAPEX, OPEX, Selling Price changing +/- 20%) was conducted to illustrate the impact of changes on the corresponding values of NPV and IRR.

The results of the sensitivity analysis, at an 8% discount rate, are presented in Table 22-3 to Table 22-5, and Figures 22-1 to 22-4.

Sensitivity of NPV and IRR to the CAPEX increase and decrease by 20% from the Base Case, is shown in Table 22-3. It must be noted that some of the OPEX items are percentages of the CAPEX. However, for the sensitivity of the CAPEX variation, the OPEX has been kept at their baseline (nominal) values.

Table 22-3. Sensitivity analysis to CAPEX variation

Overview	Case 1 Base Case (US$)	Case 2 CAPEX – 20% (US$)	Case 3 CAPEX + 20% (US$)
Capital Cost (CAPEX)	869,867,494	695,893,995	1,043,840,992
Net Present Value (NPV) Post-Tax	1,965,427,000	2,089,920,000	1,840,935,000
Net Present Value (NPV) Pre-Tax	2,830,190,000	2,972,920,000	2,687,460,000
Internal Rate of Return (IRR) Post-Tax	32.05%	38.39%	27.55%
Internal Rate of Return (IRR) Pre-Tax	40.52%	48.56%	34.81%

Sensitivity of NPV and IRR to the OPEX increase and decrease by 20% from the Base Case, is shown in Table 22-4.

Table 22-4. Sensitivity analysis to OPEX variation

Overview	Case 1 Base Case (US$)	Case 2 OPEX – 20% (US$)	Case 3 OPEX + 20% (US$)
Average Operating Cost (OPEX)	83,405,480	66,724,384	100,086,576
Net Present Value (NPV) Post-Tax	1,965,427,000	2,056,430,000	1,874,425,000
Net Present Value (NPV) Pre-Tax	2,830,190,000	2,954,481,000	2,705,899,000
Internal Rate of Return (IRR) Post-Tax	32.05%	32.97%	31.11%
Internal Rate of Return (IRR) Pre-Tax	40.52%	41.69%	39.33%

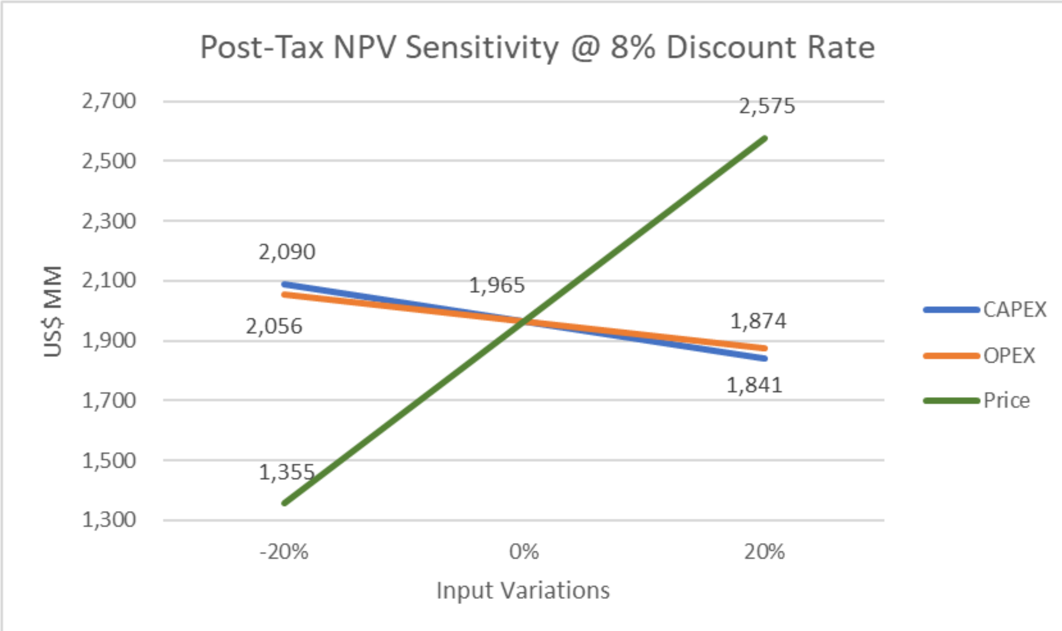
Sensitivity of NPV and IRR to the products selling price increase and decrease by 20% from the Base Case, is shown in Table 22-5.

Table 22-5. Sensitivity analysis to product price variation

Overview	Case 1 Base Case (US$)	Case 2 Revenue – 20% (US$)	Case 3 Revenue + 20% (US$)
Average Selling Price US$/Tonne LHM over lifetime of project	19,068	15,254	22,882
Net Present Value (NPV) Post-Tax	1,965,427,000	1,355,413,000	2,575,442,000
Net Present Value (NPV) Pre-Tax	2,830,190,000	1,995,697,000	3,664,683,000
Internal Rate of Return (IRR) Post-Tax	32.05%	25.58%	38.12%
Internal Rate of Return (IRR) Pre-Tax	40.52%	32.31%	48.22%

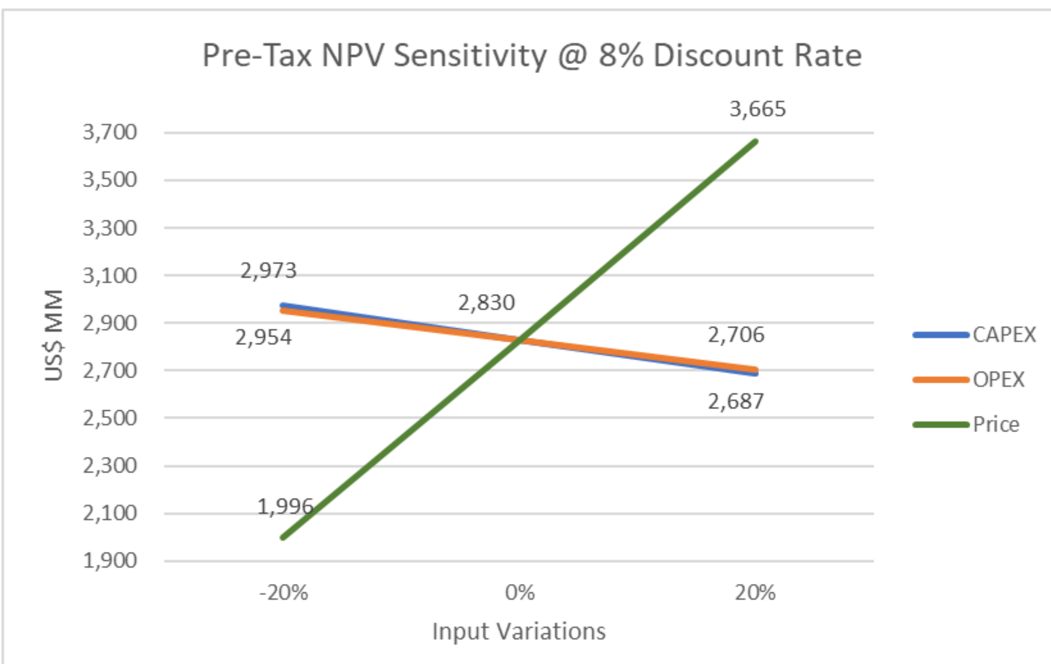
Sensitivity of Post-Tax NPV to the changes in the CAPEX, OPEX, and Selling Price by +/-20% is illustrated in Figure 22-1.

Figure 22-1. Net present value post tax sensitivity



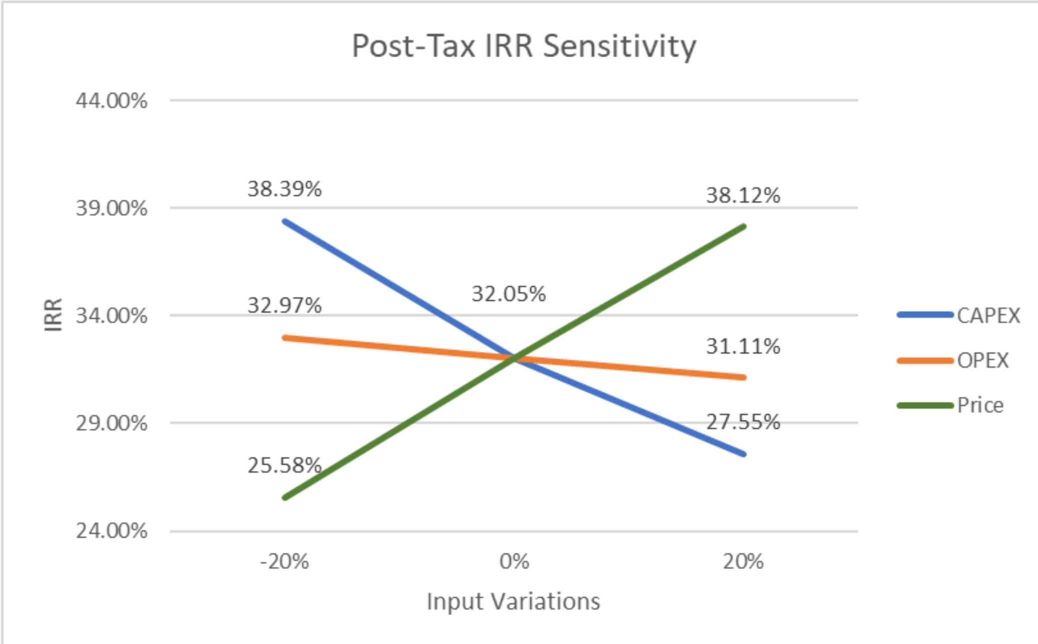
Sensitivity of Pre-Tax NPV to the changes in the CAPEX, OPEX, and Selling Price by +/-20% is illustrated in Figure 22-2.

Figure 22-2. Net present value pre-tax sensitivity



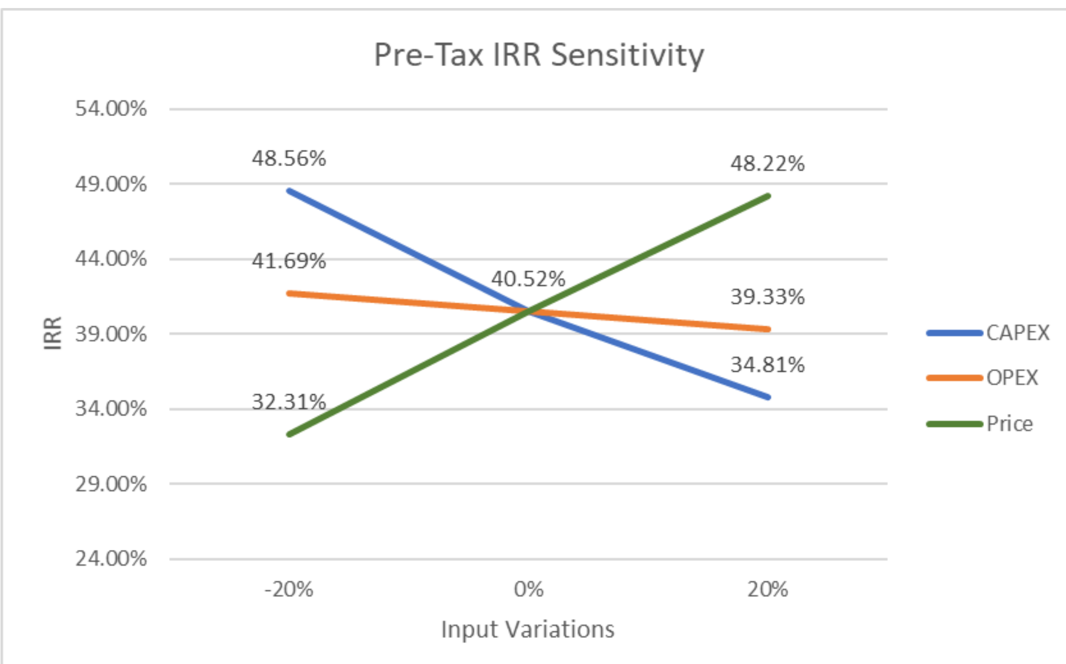
Sensitivity of Post-Tax IRR to the changes in the CAPEX, OPEX, and Selling Price by +/-20% is illustrated in Figure 22-3.

Figure 22-3. Internal rate of return post-tax sensitivity



Sensitivity of Pre-Tax IRR to the changes in the CAPEX, OPEX, and Selling Price by +/-20% is illustrated in Figure 22-4.

Figure 22-4. Internal rate of return pre-tax sensitivity



The OAT sensitivity analysis indicates that the project is as follows:

- Very sensitive to the product selling price variation.
- Moderately sensitive to the OPEX variation.
- Very sensitive to the CAPEX variation.

The SWA Project is shown to be less sensitive to variations in OPEX than to variations in CAPEX and product price when measuring IRR.

22.8 Conclusions and Sensitivity Analysis

The SWA Project's economics resulting from the assumed price scenario used in the economic model is presented in Table 22-1. A sensitivity analysis was conducted to illustrate the impact of +/-20% changes in key variables on the project's NPV and IRR (Table 22-3 to Table 22-5).

- SWA Project economics is very sensitive to the variations in the product selling price. A change in selling price by +/-20% changes the value of the Post-Tax NPV by approximately +/-10% and the value of IRR by approximately +/-6%.
- The SWA Project is relatively insensitive to variations in the OPEX. A change in the OPEX by +/-20% changes the value of the Post-Tax NPV by approximately +/-4.5% and the value of IRR by approximately +/-1%. Improvements made to process efficiency, particularly the reduction of reagents and chemicals consumption, will improve the economics of the project.
- The SWA Project economics is very sensitive to the increase or decrease of CAPEX. A change in the CAPEX by +/-20% changes the value of the Post-Tax NPV by approximately +/-6.5% and the value of IRR by approximately +/-5.0%.

This preliminary economic assessment is preliminary in nature and includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves and there is no certainty that this economic assessment will be realized. In conducting this economic assessment the authors have relied upon a number of qualifications, assumptions and estimates, the basis of which are described above.

23 Adjacent Properties

There are two major bromine producers in Arkansas: LANXESS and Albemarle Corporation (Figure 6-2). LANXESS has its Arkansas headquarters in El Dorado, Arkansas. Albemarle has Arkansas headquarters at the center of its property in Magnolia, Arkansas. The Albemarle property adjoins the eastern SWA Project boundary and LANXESS western property boundary is approximately 40 km (25 miles) further to the east.

Albemarle Corporation and subsidiaries own and operate two brine processing plants near the City of Magnolia in Columbia County (Albemarle Corporation, 2011). The plants are two of the world's largest suppliers of bromine and bromine chemicals. Albemarle's Magnolia North and South plants are fed by a network of brine production wells in Columbia County.

The LANXESS property is sub-divided into three contiguous 'units' based on the three (3) unitised areas of shared bromine operation: South, Central and West unit areas. LANXESS-owned infrastructure includes:

- Three (3) Bromine plants (1/unit area), all of which are in operation and producing bromine;
- 400 km of pipelines (250 miles); and
- 61 brine supply and reinjection wells.

According to brine production records maintained by the AOGC, LANXESS processed 660 million barrels (105 million m^3) of brine from the Smackover Formation at the LANXESS property to produce bromine and bromine-related chemicals between January 2013 and March 2018. The LANXESS property has been extracting brine and producing bromine continuously since 1957 (NI 43-101 Technical Report – Preliminary Economic Assessment of LANXESS Smackover Project, dated August 1, 2019).

Albemarle and LANXESS produce bromine-brine for use/sale in flame retardants, inorganic bromides, agricultural intermediates, tertiary amines, drilling fluids and water treatment.

It is understood from public filings that TETRA and other project developers have entered into extraneous brine leasing agreements with other mineral rights owners separate from the leases that form the basis of this PEA. This PEA does not contemplate any development from, or impact to, those extraneous leases, except for where they may be integrated as part of the contemplated future unitisation process.

The authors have not verified the information associated with adjacent properties, and the information associated with these adjacent properties may not be indicative of mineralization that may exist on, or the potential for similar development at, the SWA Project.

24 Other Relevant Data and Information

There are no other relevant data pertinent to the proposed project.

25 Interpretation and Conclusions

25.1 Opinion on Standard Lithium's Exploration Work

The exploration conducted by Standard Lithium at the SWA Project, and/or exploration components commissioned to the QP (Roy Eccles) by Standard Lithium, are in-line with defining reasonable prospects of economic extraction and completing a mineral resource estimate.

Roy Eccles P. Geol. was involved in the brine sampling, aquifer characterization and hydrogeology aspects of Standard Lithium's 2018 exploration work. The author coordinated discussion and meetings involving methodologies and interpretation resulting from the exploration work to define the geometry and hydrogeological characterization of the Upper and Middle Smackover formations aquifer and form the basis of the resource model.

The author of the relevant sections acknowledges that the data interpreted in this PEA have been used by the appropriate QP personnel and in a fashion that extracts the best possible 3D-model and hydrogeological characterization of the Upper and Middle Smackover formations aquifer. To conclude, the author, Roy Eccles has found no significant issues or inconsistencies that would cause one to question the validity of the lithium-brine concentration, subsurface geology definition and aquifer characterization results that are presented in this PEA.

25.2 SWA Property Preliminary Economic Assessment Summary

The updated 2021 SWA Project lithium-brine resource estimate is classified as 'inferred' according to the CIM definition standards. The project is an early-stage exploration project and will require further exploration and test work to elevate the resource to a higher classification level.

An objective of this PEA was to update the 2019 maiden Inferred Resource estimate, which applied a net acreage and brine ownership percentages of between 73% and 79% to the estimation process. The updated 2021 Inferred Resource estimate applies a gross acreage of 14,638 gross mineral hectares (36,172 gross mineral acres) with 100% brine ownership that is consistent with unitisation.

It is the opinion of the QP, Roy Eccles P.Geol. that proposed unitisation of the SWA Property provides reasonable justification to update the mineral resource. Unitisation within the Arkansas Brine Statute provides the most efficient pathway for the production process by protecting the production rights of the brine operator and the correlative rights of mineral interest owners. Standard Lithium's legal counsel has provided an opinion letter that it is Standard Lithium's intent to implement the unitisation process for the SWA Property at the appropriate time.

The total resource in Table 14-14 includes the breakdown of how the resource was calculated by area (i.e., North and South resource areas) and by Formation (i.e., Upper and Middle Smackover formations). The information shows that the:

- Upper Smackover Formation in the South resource area contains the highest amount of LCE (596,000 tonnes; 657,000 tons), or almost double the next sub-resource area, which include from highest to lowest LCE;
- Upper Smackover Formation - North resource area (354,000 tonnes LCE; 391,000 tons LCE);
- Middle Smackover Formation - South resource area (152,000 tonnes LCE; 167,000 tons LCE); and finally, the

- Middle Smackover Formation - North resource area (93,000 tonnes LCE; 103,000 tons LCE).

25.3 Risks and Uncertainties

25.3.1 Assumption in the Resource Model and Estimation Process

Historical lithium concentrations and the 2018 brine samples that were collected by Standard Lithium are from the Upper Smackover Formation. We assume the lithium concentration is the same for both the Upper and Middle Smackover formations as both formations are hydrogeologically connected. Additional brine sampling studies are required throughout the North and South resource areas. It is expected that geochemical variations could influence the North and South area boundaries and the overall estimation of lithium-brine resources at the SWA Property.

The thickness of the Middle Smackover Formation is based on limited data because the petro-companies have historically focussed on the Upper Smackover Formation. Consequently, we have applied a Middle Smackover Formation unit thickness of 12 m (40 feet) across the SWA Property, which is based on pick information from nine wells.

In all likelihood, the actual thickness of the Middle Smackover Formation is dependent on numerous factors in a Jurassic-aged carbonate shelf environment. Additional core analysis, drilling and/or seismic studies are required in areas where there are gaps in the geological data model, and it is expected that variations in the thickness of the Middle Smackover Formation would increase or decrease the overall volume in comparison to the estimate provided in this Technical Report.

25.3.2 Risk Assessment Summary

A risk analysis meeting was held with key members of the project team to assess initial and residual risk in the brine supply and lithium processes proposed for the SWA Project. The results of this discussion are presented in Table 25-1. The risks were evaluated before and after a risk treatment plan. The level of risk indicates whether a small or large change to the assumptions used in this PEA would result in a serious consequence to the Project's execution.

Table 25-1. Risk Assessment Matrix

Risk No.	Risk Description	Existing Controls	Initial Risk (after Existing Controls)	Risk Treatment Plan	Residual Risk
1	Brine production of 1,800 m^3/h and/or lithium concentration of 399 mg/L not available. Includes associated drilling risk.	A geological assessment, in addition to testing existing brine supply wells	Medium	Additional testing of existing and new brine supply wells is planned.	Low

Risk No.	Risk Description	Existing Controls	Initial Risk (after Existing Controls)	Risk Treatment Plan	Residual Risk
2	If innovative lithium extraction process does not perform as expected, could result in higher OPEX and CAPEX.	Extended pilot tests completed.	Low	Continued operation and process optimization of Demonstration Plant operation. This will also not be the first commercial plant of this type	Low
3	If electrochemical and associated Lithium Hydroxide conversion process does not perform as expected, it could result in higher OPEX and CAPEX.	Based on existing chloralkali industry technology and specific experience with Lithium solutions.	Medium	Long-term membrane testing with representative enriched LiCl solution planned, as well as pilot testing of commercial-scale electrochemical cells.	Low
4	If market price of LHM drops, project economics will be negatively affected.	Demand is increasing faster than supply is coming to the market. Sensitivity analysis shows favourable economics even for significantly lower Lithium Hydroxide price.	High	To evaluate alternate contracts with vendors to mitigate short term price decline.	High
5	Global supply chain shortages / delays could influence schedule and CAPEX	Understanding long-lead items that would be impacted by supply chain constraints	Medium	A mitigating action plan will be put in place to minimize supply chain risk.	Low
6	If natural disaster occurs (e.g., tornado, earthquake), could result in loss of production.	Understanding of current risks at plant location.	Medium	Engineering of the plant will take into account weather risks. Provide shelter for personnel. Design critical facilities to withstand moderate tornados and earthquakes. Carry special insurance.	Low
7	If unknown infringement of sorbent and process patents occurs, could result in licensing claims.	Conducted freedom to operate searches.	Medium	Continue patent research. Ensure contingency funds in place to cover licensing fees.	Low
8	Construction cost/schedule overruns	25% contingency included in current economics. Sensitivity analysis shows favourable economics even for higher CAPEX	Medium	Work with experienced EPC contractor; lump-sum turnkey where possible. PFS will provide improved cost confidence.	Low

Risk No.	Risk Description	Existing Controls	Initial Risk (after Existing Controls)	Risk Treatment Plan	Residual Risk
9	Lithium brine royalty assessment by the Arkansas Oil and Gas Commission is not completed in a timely manner and/or the royalty rates overly impact project economics.	Established process completed for bromine and most recently for calcium chloride and magnesium chloride	Medium	Work with experienced and qualified team and engage stakeholders early in the process.	Low

As with any development project there exists potential risks and uncertainties. Standard Lithium will attempt to reduce risk/uncertainty through effective project management, engaging technical experts and developing contingency plans.

26 RECOMMENDATIONS

As per the CIM guidelines for lithium-brine, and when reporting higher level of resource classification than reported in this PEA (i.e., Indicated and Measured Brine Resources), the QP's must consider only those resources that are, or may become, recoverable under reasonably assumed technical and economic conditions. The logical next steps and work recommendations for Standard Lithium to elevate the SWA Project to a higher level of resource classification and project definition is to:

1. Collect additional brine samples from the Upper and Middle Smackover Formations either from existing wells on the Property, or recomplete existing/abandoned wells or install new wells (US$1.5mm);
2. Analyse available Smackover Formation core at several locations from the Arkansas Geological Survey at 0.3 m intervals throughout the Upper and Middle Smackover Formations to assess porosity and permeability (US$0.1mm);
3. Perform long-duration pumping tests to confirm aquifer properties (US$0.9mm);
4. Complete reservoir and resource modelling (US$0.75mm);
5. Continue with ongoing direct lithium extraction pre-commercial demonstration using brines from the SWA Project (US$0.75mm);
6. Conduct lithium chloride to lithium hydroxide conversion at suitable scale (US$1.0mm);
7. Complete additional permitting and environmental studies where appropriate (US$0.5mm); and,
8. Conduct all additional necessary engineering and pre-feasibility studies to integrate the project development findings into an updated resource classification and PFS (US$1.5mm).

The authors recommend Standard Lithium approaches accomplishing these tasks over a two-year period. The total estimated cost of the recommended work including contingency is US$7,000,000.

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28 CERTIFICATE OF AUTHORS

The certificates can be found on the following pages.

I, Rodney Breuer, Professional Engineer, do hereby certify that:

1. I am Vice President of Engineering, Compliance and Construction, Inc (ECCI), located in Little Rock, Arkansas.
2. I graduated with a B.Sc. in Civil Engineering from the University of Missouri-Rolla in 1979 and a M.Sc. in Civil Engineering the University of Missouri-Rolla in 1980.
3. I am and have been registered as a Professional Engineer since 1984.
4. I have worked as an engineer in the environmental industry for 40 years, since my graduation.
5. I have read the definition of "Qualified Person" set out in National Instrument 43-101 (NI 43-101) and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101.
6. I oversaw the preparation and am responsible for the Environmental Studies, Permitting and Social or Community Impact in Section 20 of the Technical Report titled "SW Arkansas Lithium Project *Arkansas, United States*", with an effective date of November 20, 2021 and an amended issue date of June 16, 2023 (the "Technical Report").
7. I have not visited the SW Arkansas Property with respect to this Technical Report.
8. I am not aware of any scientific or technical information with respect to the subject matter of the Technical Report that is not reflected in the Technical Report, the omission to disclose which makes the Technical Report misleading.
9. I am independent of the Issuer as per NI 43-101 and successfully pass the independence requirements of the Guidance of Independence test in NI 43-101 CP Item 1.5. I am not an employee, insider, director or partner of the Issuer and do not hold any securities or direct/indirect interests related to the Issuer or the Property and/or adjacent properties that is the subject of this Technical Report.
10. I have read National Instrument 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them for regulatory purposes, including electronic publication in the public company files or their websites.

Rodney Breuer, P.Eng.

Effective date: November 20, 2021
Signature date: June 16, 2023
Little Rock, Arkansas, United States

STATE OF ARKANSAS
REGISTERED PROFESSIONAL ENGINEER
No.7115
RODNEY BREUER
6/16/23

I, D. Roy Eccles, P. Geol., do hereby certify that:

1. I am a Senior Consulting Geologist and Chief Operations Officer of APEX Geoscience Ltd., #100, 11450 – 160th Street, Edmonton, Alberta T5M 3Y7.
2. I graduated with a B.Sc. in Geology from the University of Manitoba in Winnipeg, Manitoba in 1986 and with a M.Sc. in Geology from the University of Alberta in Edmonton, Alberta in 2004.
3. I am and have been registered as a Professional Geologist with the Association of Professional Engineers and Geoscientists (APEGA) of Alberta since 2003.
4. I have worked as a geologist for more than 35 years since my graduation from university and have been involved in all aspects of global mineral exploration, mineral research, and mineral resource estimations for metallic, industrial, and specialty mineral projects and deposits.
5. I have read the definition of "Qualified Person" set out in National Instrument 43-101 (NI 43-101) and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101. I have explored for and prepared mineral resource models and estimations for lithium-brine projects in western Canada, southern United States, central Europe, and other international destinations.
6. I oversaw the preparation, and am responsible for, the technical information included in Sections 4-12, 14, and 23 of the Technical Report titled "Preliminary Economic Assessment of SW Arkansas Lithium Project", with an effective date of November 20, 2021 and an amended issue date of June 16, 2023 (the "Technical Report).
7. I visited the SWA Property on March 5 to 9, 2018 and can verify the brine sampling program, infrastructure at the SWA Property, including oil and gas wells, the pipeline network and primary and secondary road network.
8. To the best of my knowledge, information and belief, the Technical Report contains all relevant scientific and technical information that is required to be disclosed, to make the Technical Report not misleading.
9. I have read National Instrument 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.
10. I am independent of the Issuer, and the SW Arkansas Property, as per NI 43-101 and successfully pass the independence requirements of the Guidance of Independence test in NI 43-101 CP Item 1.5.
11. I have been involved with the project in the preparation of the following report:

    Eccles, D.R., Molnar, R., and Rakhit, K. (2019): Geological introduction and Maiden Inferred Resource Estimate for Standard Lithium Ltd.'s Tetra Smackover Lithium-Brine Property in Arkansas, United States; Technical Report prepared for Standard Lithium Ltd., Effective Date 28 February 2019, 159 p.

12. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them for regulatory purposes, including electronic publication in the public company files or their websites.

PROFESSIONAL GEOLOGIST ALBERTA
D. ROY ECCLES
16 Jun 2023

PERMIT TO PRACTICE
APEX GEOSCIENCE LTD.
RM SIGNATURE:
RM APEGA ID #: 74150
DATE: 16 Jun 2023
PERMIT NUMBER: P005824
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

D. Roy Eccles, M.Sc., P. Geol.

Effective date: November 20, 2021
Signature date: June 16, 2023
Edmonton, Alberta, Canada

I, Trotter Hunt, Professional Engineer, do hereby certify that:

1. I am Vice President of Hunt, Guillot & Associates LLC, 603 E Reynolds Drive, Ruston, Louisiana, 71270, United States of America.
2. I graduated with a Bachelor of Science Degree in Mechanical Engineering from Georgia Institute of Technology in 1999 and Master's Degree in Business Administration in 2004 from Vanderbilt University.
3. I am registered as a Professional Engineer in Louisiana, Texas, South Carolina, New York, New Jersey, Florida, West Virginia, and multiple other states since 2009.
4. I have worked as a mechanical engineer in the petroleum, natural gas, specialty chemical and multiple other industries for 21 years, since my graduation from university.
5. I have read the definition of "Qualified Person" set out in National Instrument 43-101 (NI 43-101) and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101.
6. I oversaw the preparation and am responsible for Sections 16.2 – 16.4, 18, 21 and 22 the Technical Report titled "SW Arkansas Lithium Project *Arkansas, United States*", with an effective date of November 20, 2021 and an amended issue date of June 16, 2023 (the "Technical Report").
7. I made one (1) visit to the SW Arkansas Property on November 20, 2021 to observe the proposed location for the facility and associated infrastructure.
8. I am not aware of any scientific or technical information with respect to the subject matter of the Technical Report that is not reflected in the Technical Report, the omission to disclose which makes the Technical Report misleading.
9. I am independent of the Issuer as per NI 43-101 and successfully pass the independence requirements of the Guidance of Independence test in NI 43-101 CP Item 1.5. I am not an employee, insider, director or partner of the Issuer and do not hold any securities or direct/indirect interests related to the Issuer or the Property and/or adjacent properties that is the subject of this Technical Report.
10. I have read National Instrument 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them for regulatory purposes, including electronic publication in the public company files or their websites.

Trotter Hunt, Professional Engineer

Effective date: November 20, 2021
Signature date: June 16, 2023
Ruston, Louisiana, United States

STATE OF LOUISIANA
ALEXANDER TROTTER HUNT
License No. 34722
PROFESSIONAL ENGINEER

I, David Anthony (Tony) Boyd, Ph.D., P.Eng., do hereby certify that:

1. I am a process engineer employed at NORAM Electrolysis Systems Inc., located at #1800-200 Granville St., Vancouver, British Columbia, V6C 1S4 and as of the effective date of the Technical Report I was employed by NORAM Engineering and Constructors Ltd. located at #1800-200 Granville Street, Vancouver, British Columbia, V6C 1S4.
2. I am a graduate of the University of British Columbia, Canada with a B.A.Sc. in Chemical Engineering (1990) and a Ph.D. in Chemical Engineering (2006).
3. I am a Registered Professional Engineer (P.Eng.) with the Engineers and Geoscientists of British Columbia (EGBC) with Registration Number 24424 (June 1999).
4. As of the effective date of the technical report, I had over 30 years of process engineering experience in a variety of technology areas, including nitration, sulphuric acid and electrochemistry. I have worked in the area of electrolysis to produce lithium hydroxide for over seven years through NORAM's development of its Norscand® electrolyser, including operations at NORAM's pilot plant (Richmond, BC) and Nemaska Lithium's P1P demonstration plant (Shawinigan, QC). I was the QP for the electrolysis portion of Nemaska Lithium's NI 43-101 Feasibility Studies (2017, 2019).
5. I have read the definition of "Qualified Person" set out in National Instrument 43-101 (NI 43-101) and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101.
6. I was the supervisor of the engineer (Eric Mielke, P.Eng.) involved in the preparation of Sections 1, 2, 3, 17, 19, 24, 25, 26 and 27 of the Technical Report titled "SW Arkansas Lithium Project *Arkansas, United States"*, with an effective date of November 20, 2021 and an amended issue date of June 16, 2023 (the "Technical Report"), and I am responsible for Sections 2, 3, 17, 19, 24, 25, 26 and 27. For the summary chapter (Section 1), I am responsible for the content to be consistent with the subsequent report chapters.
7. I have not visited the SW Arkansas Property with respect to this Technical Report.
8. As at the effective date of the Technical Report, to the best of knowledge, information and belief, the Technical Report, or part(s) thereof that I am responsible for, contains all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
9. I am independent of the Issuer as per NI 43-101 and successfully pass the independence requirements of the Guidance of Independence test in NI 43-101 CP Item 1.5. I am not an employee, insider, director or partner of the Issuer and do not hold any securities or direct/indirect interests related to the Issuer or the Property and/or adjacent properties that is the subject of this Technical Report.
10. I have read National Instrument 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them for regulatory purposes, including electronic publication in the public company files or their websites.

PROFESSIONAL
PROVINCE
OF
D.A. BOYD
BRITISH
COLUMBIA
ENGINEER

Tony Boyd

David Anthony (Tony) Boyd, Ph.D., P.Eng.

Effective date: November 20, 2021
Signature date: July 17, 2023
Vancouver, British Columbia, Canada

I, Dr. Ronald Molnar, Professional Engineer, do hereby certify that:

1. I am Owner and President of: METNETH2O Inc., 1816 Parkwood Circle, Peterborough, ON K9J 8C2.
2. I graduated with a B.Eng. in Metallurgy from McGill University in 1972 and a Ph.D. in Metallurgy from the Imperial College, Royal School of Mines, London, England in 1980.
3. I am and have been registered as a Professional Engineer with the Professional Engineers Ontario (PEO) since 2008.
4. I have worked as a hydrometallurgist for over 40 years, including over 36 years of experience in extraction of metals from aqueous solutions and purification of metallurgical solutions, since my graduation from university. I currently specialize in solvent extraction and ion exchange, test program design, pilot plant design, and data analysis for bench-scale and pilot plant programs.
5. I have read the definition of “Qualified Person” set out in National Instrument 43-101 (NI 43-101) and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a “Qualified Person” for the purposes of NI 43-101.
6. I oversaw the preparation and am responsible for the technical information included in Section 13 (Mineral Processing and Metallurgical Testing) of the Technical Report titled “Preliminary Economic Assessment of SW Arkansas Lithium Project”, with an effective date of November 20, 2021 and an amended issue date of June 16, 2023 (the “Technical Report”).
7. I have not visited the SWA Property with respect to this Technical Report.
8. I am not aware of any scientific or technical information with respect to the subject matter of the Technical Report that is not reflected in the Technical Report, the omission of the disclosure of which would render the Technical Report misleading.
9. I am independent of the Issuer as per NI 43-101 and successfully pass the independence requirements of the Guidance of Independence test in NI 43-101 CP Item 1.5. I am not an employee, insider, director or partner of the Issuer and do not hold any securities or direct/indirect interests related to the Issuer or the Property and/or adjacent properties that are the subject of this Technical Report. I work as a contractor on a project basis at an hourly rate and have not received income beyond the 3-years proceeding the Effective Date of this Technical Report.
10. I have read National Instrument 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them for regulatory purposes, including electronic publication in the public company files or their websites.

Ronald Molnar

Ronald Molnar, Ph.D., P. Eng (ON)

Effective date: November 20, 2021
Signature date: June 26, 2023
Peterborough, Ontario, Canada

I, Steve Shikaze, Professional Engineer, do hereby certify that:

1. I am a self-employed Senior Hydrogeological Engineer based in Waterloo, Ontario, and as of the effective date of the Technical Report I was employed by Matrix Solutions Inc. located at 7B-650 Woodlawn Road W., Guelph, Ontario, N1K 1B8.
2. I graduated with a B.A.Sc. in Geological Engineering from the University of Waterloo in 1990 and a M.Sc. in Earth Sciences (Hydrogeology) from the University of Waterloo in 1993.
3. I am and have been registered as a Professional Engineer with the Professional Engineers of Ontario since 2006.
4. I have worked as a hydrogeologist in the environmental industry for 30 years since my graduation from university.
5. I have read the definition of “Qualified Person” set out in National Instrument 43-101 (NI 43-101) and certify that by reason of my education, affiliation with a professional association (as defined in NI 43-101) and past relevant work experience, I fulfill the requirements to be a “Qualified Person” for the purposes of NI 43-101.
6. I oversaw the preparation and am responsible for the hydrogeological information included in Section 16.1 (Estimated Brine Production Capacity of the Technical Report titled “SW Arkansas Lithium Project *Arkansas, United States”*, with an effective date of November 20, 2021 and an amended issue date of June 16, 2023 (the “Technical Report”).
7. I have not visited the SW Arkansas Property with respect to this Technical Report.
8. I am not aware of any scientific or technical information with respect to the subject matter of the Technical Report that is not reflected in the Technical Report, the omission to disclose which makes the Technical Report misleading.
9. I am independent of the Issuer as per NI 43-101 and successfully pass the independence requirements of the Guidance of Independence test in NI 43-101 CP Item 1.5. I am not an employee, insider, director or partner of the Issuer and do not hold any securities or direct/indirect interests related to the Issuer or the Property and/or adjacent properties that is the subject of this Technical Report.
10. I have read National Instrument 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them for regulatory purposes, including electronic publication in the public company files or their websites.

Steve Shikaze, M.Sc., P.Eng.

Effective date: November 20, 2021
Signature date: June 16, 2023
Waterloo, Ontario, Canada