ESTIMATES

of

PROSPECTIVE RESOURCES

to the

RECONNAISSANCE ENERGY AFRICA LTD. INTEREST

in

CERTAIN OPPORTUNITIES

located in the

DAMARA FOLD AND THRUST BELT PLAY AREA

in

PETROLEUM EXPLORATION LICENSE 73 KAVANGO BASIN, NAMIBIA

as of

MARCH 31, 2023

UPDATED

Prepared in accordance with

CANADIAN NATIONAL INSTRUMENT 51-101

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

December 8, 2023

Mr. Brian Reinsborough
Chief Executive Officer
Reconnaissance Energy Africa Ltd.
999 West Hastings Street, Suite 1500
Vancouver, BC
Canada, V6C 2W2

Dear Mr. Reinsborough:

In accordance with your request, we have estimated the prospective resources, as of March 31, 2023, to the Reconnaissance Energy Africa Ltd. (ReconAfrica) interest in certain opportunities subclassified as prospects located in the Damara Fold and Thrust Belt play area in the southwestern to south-central portion of Petroleum Exploration License (PEL) 73 in the Kavango Basin, northeastern Namibia. This is an update of our report dated August 16, 2023, to include chance of development. With the exception of this change, we completed our evaluation on or about June 22, 2023. It is our understanding that ReconAfrica holds a 90 percent interest in PEL 73. The Namibian state oil company, NAMCOR, holds the remaining 10 percent interest in PEL 73, and ReconAfrica carries NAMCOR's costs through the development stage. PEL 73 has an exploration period comprising a number of phases ending January 29, 2025, or, if extensions are requested and granted, ending January 29, 2029. The preparation date of this report is June 1, 2023; we did not consider any geological, engineering, or financial data for this evaluation after that date.

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

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in Canadian National Instrument 51-101 (NI 51-101)—Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook (COGEH). However, this report does not contain all the supplemental data required by NI 51-101 and the COGEH. As presented in the COGEH, reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification. Contingent and prospective resources estimates involve additional risks, specifically the risk of not achieving commerciality and exploration risk, respectively, not applicable to reserves estimates. Therefore, when resources classifications are combined, it is important that each component of the summation also be provided and it should be made clear whether and how the components in the summation were adjusted for risk. Definitions are presented immediately following this letter. Following the definitions is a list of abbreviations used in this report.

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

We estimate the unrisked and risked gross (100 percent) prospective gas resources and the unrisked and risked company gross prospective gas resources to the ReconAfrica interest in these prospects, as of March 31, 2023, to be:

Best Estimate (2U) Prospective Gas Resources (Bcf)					
Unrisked			Risked[1]		
Gross (100%)	Company Gross	Net[2]	Gross (100%)	Company Gross	Net[2]
14,548.8	13,093.9	12,439.2	777.6	699.9	664.9

Note: Prospective resources are the arithmetic sum of multiple probability distributions.

(1) These estimates are based on unrisked prospective resources that have been risked for chance of discovery and chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

(2) Net prospective resources are after royalty deductions.

Gas volumes are expressed in billions of cubic feet (Bcf) at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. As requested, low estimate and high estimate prospective resources have not been included in this report. For the purposes of this report, the volumes and parameters associated with the best estimate scenario of prospective resources are referred to as 2U. The 2U prospective resources have been aggregated beyond the prospect level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation. Statistical principles indicate that the arithmetic sums of multiple estimates may be misleading as to the volumes that may actually be recovered.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. The estimates for risked resources are derived directly from the estimates for unrisked resources, incorporating a geologic risk assessment for each prospect; such risked resources also incorporate a development risk assessment. The prospective resources included in this report represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made; prospective resources have both an associated chance of discovery and a chance of development, which together define the chance of commerciality.

Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics;

(2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation.

Development risking addresses the probability of development given geologic success; this risk analysis is conducted based on the associated economic and development related factors (development plan, production forecasts, markets, facilities, capital and operating costs, product prices, approvals, etc.). For the purposes of this assessment of development risk, we have considered the primary elements to be (1) financial considerations, (2) access to sales markets, (3) development plan approval, and (4) government and regulatory approvals.
Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements for each prospect.

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

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

As shown in the Table of Contents, this report includes a discussion, a location map, pertinent figures, a summary of reservoir parameters, a summary of prospective resources, and a bibliography.

For the purposes of this report, we did not perform any field inspection of the prospects. Based on the information used in our analysis, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the prospects.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, and property ownership interests. The prospective resources in this report have been estimated using probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserves information included in the COGEH (COGEH Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with COGEH definitions and guidelines. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from ReconAfrica, public data sources, and the nonconfidential files of Netherland, Sewell and Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the

COGEH Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

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

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
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By: Joseph Wolfe
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NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Consolidated 3rd Edition of the Canadian Oil and Gas Evaluation Handbook Prepared by the Society of Petroleum Evaluation Engineers (Calgary Chapter), August 2018, Updated January 2022

1.3.2 Terminology: Resources and Reserves

Petroleum is defined as a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid, or solid phase. The term "Resources" encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Accordingly, the term "total Resource" is equivalent to Petroleum Initially-In-Place (PIIP) and it is recommended the term "PIIP" be used rather than "total Resources" to avoid any confusion that may result from the mixed historical usage of the term "Resource" to mean only the recoverable portion of PIIP.

The term Recoverable Resources is sometimes used to denote a sum of Reserves, Contingent Resources, and Prospective Resources.

1.3.3 Projects and Scenarios

The concepts of projects and scenarios are fundamental to COGEH.

A project is:

- A defined activity or set of activities for the discovery or recovery of oil or gas and related by-products, or other naturally occurring subsurface liquid or gaseous commodities.
- A project provides the basis for the assessment and classification of Resources.

A scenario is:

- A specific exploration or development plan for the execution of a project, with sufficient details (planned or assumed) to facilitate an estimate of potential volumes and the preparation of capital, production and operating cost forecasts to enable cash flow analysis.

The level of detail of a scenario will depend on the information available. Early in the life of a project, scenarios can vary widely with respect to recovery mechanism, facility capacities, construction methods, and development timing, etc.

1.3.4 Levels of Evaluation and Reporting

There are three important levels at which estimates are made and recorded for Resource management and reporting.

- **Resource (or Reserve) Entity:** The discrete part of an oil and gas asset for which a Resource estimate is prepared. For example, a Reserve entity may be an individual well zone, a group of well zones, or a pool. A Prospective Resource entity might be a play.
- **Property Resource Class (or Reserve):** In COGEH, "property" is a term used to describe a grouping of oil and gas Reserve entities in a common geographic area (e.g., a field). Properties are defined primarily for asset management purposes to facilitate functions such as production and financial accounting and land, contract, and records management. Property Reserve will typically, but not always, consist of the estimates for multiple Reserve entities.
- **Reported Resources (or Reserve):** The sum of all individual Resource estimates to be contained in a report. There are specific requirements for reported Reserve estimates for all Reserve entities in all properties presented in a Qualified Reserves Evaluator's (QRE) report. Reported Reserves commonly refers to the corporate total Reserves a company owns.

The evaluation process begins with estimating Resource at the entity level, following which the entity level estimates are aggregated to provide the total for properties, company, reporting or other enterprise.

1.3.5 The Petroleum Resource Management System and Resource Definitions

COGEH uses the SPE-PRMS classification (see Figure 1-1), for which:

- CLASS forms the vertical axis of the PRMS diagram and represents the COC. It describes the relative maturity of exploration and development projects. Assignment to a Class depends on the extent to which various conditions are satisfied.

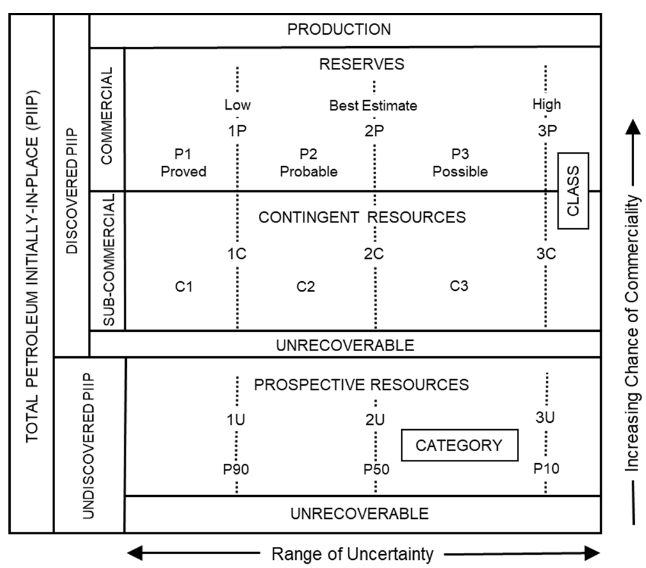

Figure 1-1 SPE-PRMS Resources Classification System

- CATEGORY forms the horizontal axis of the PRMS framework and provides a measure of the uncertainty in estimates of a Resource CLASS.

The following definitions relate to the subdivisions in the Resources classification framework of Figure 1-1 and use the primary nomenclature and concepts contained in the 2018 SPE-PRMS.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations and is potentially producible. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total Resources").

Discovered PIIP (equivalent to discovered Resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The Discovered PIIP includes production, Reserves, and Contingent Resources; the remainder is unrecoverable.

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Although the volume of all fluid produced from a reservoir and measured at the wellhead is essential for reservoir engineering analyses, the production referred to in the PRMS classification is the volume of specific product types that is delivered to and measured at a specific reference point (a reference, sales or transfer point) that excludes any volumes that are not delivered at that point.

Reserves are estimated remaining quantities of commercially recoverable oil, natural gas, and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Reserves are further categorized according to the level of certainty associated with the estimates and may be sub-classified based on development and production status.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development (TUD) but are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are further categorized according to the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Contingencies may include economic, environmental, social and political factors, regulatory matters, a lack of markets, and a prolonged timetable for development. Contingent Resources have a Chance of Development that is less than certain.

Undiscovered PIIP (equivalent to undiscovered Resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The potentially recoverable portion of Undiscovered PIIP is referred to as "Prospective Resources," the remainder as "unrecoverable."

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by applying future development projects. Prospective Resources have both an associated Chance of Discovery and a Chance of Development. Prospective Resources are further categorised according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Unrecoverable is that portion of Discovered or Undiscovered PIIP quantities that is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Resources may be unrecoverable because:

- There is no known technically viable recovery process for any portion of a Resource.
- Of other contingencies, including, but not limited, to lack of market access, regulatory approval, or social or environmental objections.

The sum of Reserves, Contingent Resources, and Prospective Resources is described as "Recoverable Resources" but has significant potential to be misunderstood. It is valuable for activities such as regional studies, but without an explanation and a full understanding of what it represents, it is inadequate for investment decisions. When a report includes an estimate of Recoverable Resources, it must specify:

- Which Resource classes are included: Reserves, Contingent Resource and/or Prospective Resource, and the relative proportions.
- Whether it is risked or un-risked with respect to Chance of Discovery and Chance of Development (e.g., Chance of Commerciality).

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Consolidated 3rd Edition of the Canadian Oil and Gas Evaluation Handbook Prepared by the Society of Petroleum Evaluation Engineers (Calgary Chapter), August 2018, Updated January 2022

- The uncertainty Category for which the summation has been carried out. This should always include the sum of the Best estimates. The arithmetic summation of Low and, especially High estimates has significant potential to be misleading and is not recommended.

Regulatory agencies may forbid the disclosure of the sums of Reserves, risked or un-risked Contingent and Prospective Resource Classes because they can be misleading.

1.3.6 Project Maturity Sub-Classes

Project Maturity Sub-Classes (See Figure 1-2) describe the stage of an exploration or development project and correspond to the Chance of Commerciality (COC) of the project. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required to move the project up the maturity "ladder" towards commercial production. The Project Maturity Sub-Classes are those of the SPE-PRMS with further guidance in Section 2.1.3.5 of the Petroleum Resources Management System, Revised, June 2018.

The use of Project Maturity Sub-Classes is relevant for all Resource Classes and is a recommended best practice. A report of a project maturity sub-class may be accompanied by an estimate of the probability of progressing to the next level of maturity.

Project Maturity Sub-Classes for Reserves are: On Production, Approved for Development and Justified for Development and describe those actions that progress identified Reserves associated with a defined project through final approvals to implementation and initiation of production and product sales.

Project Maturity Sub-Classes for Contingent Resources are: Development Pending, Development on Hold, Development Unclarified and Development Not Viable and are consistent with the 2018 PRMS.

Project Maturity Sub-Classes for Prospective Resources are: Play, Lead, Prospect. These classes describe a progression in each of which, potential accumulations are evaluated according to their Chance of Discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects.

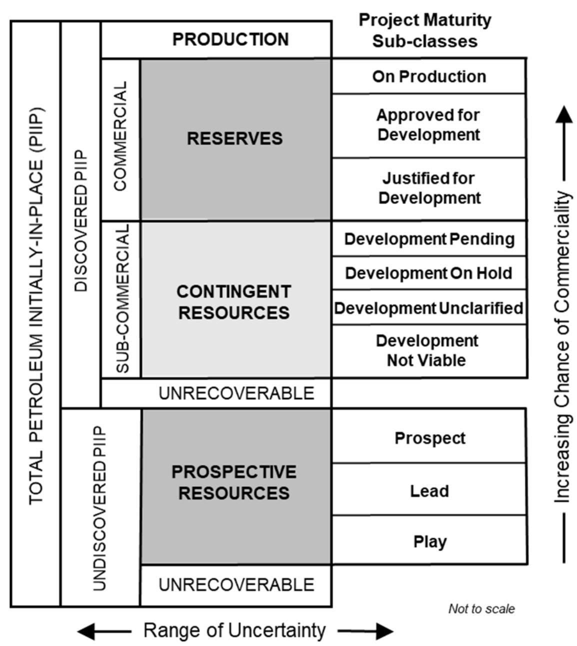

Figure 1-2 Sub-classes based on project maturity

1.3.7 Classification of Recoverable Resources

For petroleum quantities associated with simple conventional reservoirs, the divisions between the Resource Classes defined in Section 1.3.5 – The Petroleum Resource Management System and Resource Definitions may be clear, and the basic definitions alone may suffice for differentiation between classes. For example, the drilling and testing of a well in a simple structural accumulation may be sufficient to allow classification of the entire estimated recoverable quantity as Contingent Resources or Reserves. However, as the industry has trended toward the exploitation of more complex and costly petroleum sources, the divisions between Resource Classes have become less distinct, and accumulations may have several classes of Resources simultaneously. For example, in extensive "basin-centered" low-permeability gas plays, the division between all classes of remaining recoverable quantities, (e.g., Reserves, Contingent Resources, and Prospective Resources), may be highly interpretive. Consequently, additional guidance is necessary to promote consistency in classifying Resources. The following provides some clarification of the key criteria that delineate Resources.

1.3.7.1 Discovery Status

As shown in Figure 1-2, the Total PIIP is first sub-classified based on the discovery status of a petroleum accumulation. Discovered PIIP, production, Reserves, and Contingent Resources are associated with known accumulations. Recognition as a known accumulation requires the accumulation be penetrated by a well and have evidence of the existence of petroleum.

1.3.7.2 Commercial Status

Commercial status differentiates Reserves from Contingent Resources. The criteria that should be considered in determining commerciality includes:

- The project is economically viable;
- There is a market for the forecast sales quantities of production required to justify development;
- The necessary production, transportation facilities and access to infrastructure are available or can be made available;

- The regulatory, environmental, societal and political conditions will allow for the actual implementation of the recovery project being evaluated; and
- All required internal and external approvals are forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approvals for expenditures, etc.

1.3.7.3 Commercial Risk

Estimates of recoverable quantities are stated in terms of a product type delivered to a reference point (typically a custody transfer or sales point) derived from a development program, assuming commercial development. It must be recognized that Reserves, Contingent Resources, and Prospective Resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the COC. The COC varies in different classes of Recoverable Resources as follows:

- **Reserves:** To be classified as Reserves, estimated recoverable quantities must be associated with a project(s) that is in a known accumulation with a COC that is effectively 100 percent.
- **Contingent Resources:** Have been discovered and are recoverable using established technology or potentially recoverable with TUD. But not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal and other conditions over the life of the project. For Contingent Resources, the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the Chance of Development. For Contingent Resources the COC is equal to the Chance of Development.
- **Prospective Resources:** A Prospective Resource is an estimate of what may be recovered if a discovery is made and developed, but not all exploration projects will result in discoveries and not all discoveries will be developed. The chance that an exploration project will result in the discovery of petroleum is referred to as the Chance of Discovery. Thus, for an undiscovered accumulation the COC is the product of two risk components; the Chance of Discovery and the Chance of Development.

1.3.7.4 Economic Status

Demonstration of economic viability is a prerequisite for classification as a Reserve.

In examining the economic viability of Contingent Resources, the same fiscal conditions should be applied as in the estimation of Reserves, (e.g., specified economic conditions), which are generally accepted as being reasonable. By definition, Reserves are commercially (and hence economically) recoverable, but a Contingent Resources that has satisfied other relevant contingencies may or may not be economically viable and can be sub-classified by economic status:

- Economic Contingent Resources are those Contingent Resources that are currently economically recoverable.
- Sub-economic Contingent Resources are those Contingent Resources that are not currently economically recoverable.

The designation of a Contingent Resource as sub-economic implies there is a reasonable chance it could become economic within the foreseeable future. If this is not the case, the classification must be development not viable or unrecoverable Discovered PIIP.

Where evaluations are incomplete, such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is undetermined (e.g., "Contingent Resource – economic status undetermined") and in which case the Project Maturity Sub-Class would be Development Unclarified.

Classification as a Prospective Resource implies an expectation of economic viability but the assessment of this is likely to be less rigorous than for Reserves or Contingent Resource.

1.3.7.5 Uncertainty Categories

Estimates of Resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project. Consequently, estimates of Resources should generally be quoted according to the level of confidence associated with the estimates. An understanding of statistical concepts and terminology is essential to understanding the confidence associated with Resource definitions and categories.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as Low, Best, and High estimates as follows:

- **Low Estimate:** This is considered to be a conservative estimate of the quantity that will be recovered. It is likely the actual remaining quantities recovered will exceed the Low Estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) the quantities actually recovered will equal or exceed the Low Estimate.
- **Best Estimate:** This is considered to be the Best Estimate of the quantity that will be recovered. It is equally likely the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

- **High Estimate:** This is considered to be an optimistic estimate of the quantity that will be recovered. It is unlikely the actual remaining quantities recovered will exceed the High Estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) the quantities actually recovered will equal or exceed the High Estimate.

1.3.8 Definitions of Reserves

The following Reserves definitions and guidelines are designed to assist evaluators in making Reserves estimates on a reasonably consistent basis and assist users of evaluation reports in understanding what such reports contain and, if necessary, in judging whether evaluators have followed generally accepted standards. The guidelines outline:

- general criteria for classifying Reserves,
- procedures and methods for estimating Reserves,
- confidence levels of individual entity and aggregate Reserves estimates,
- verification and testing of Reserves estimates.

The following definitions apply to both estimates of individual Reserves entities and the aggregate of Reserves for multiple entities.

1.3.8.1 Reserves Categories

Reserves are categorized according to the probability that at least a specific volume will be produced.

In a broad sense, Reserves categories reflect the following expectations regarding the associated estimates:

Reserves Category	Confidence Characterization
Proved (1P)	Low Estimate, Conservative
Proved + Probable (2P)	Best Estimate
Proved + Probable + Possible (3P)	High Estimate, Optimistic

1.3.8.1.1 Proved Reserves

Proved Reserves are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely the actual remaining quantities recovered will exceed the estimated Proved Reserves.

1.3.8.1.2 Probable Reserves

Probable Reserves are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved + Probable Reserves.

1.3.8.1.3 Possible Reserves

Possible Reserves are those additional Reserves that are less certain to be recovered than Probable Reserves. It is unlikely the actual remaining quantities recovered will exceed the sum of the estimated Proved + Probable + Possible Reserves.

Stand-alone Possible Reserves may be assigned to a property for which no Proved or Probable Reserves volumes have been assigned but would be rare. Circumstances for doing so could include any one or more of the following:

- Project economics are such that no Proved or Probable Reserves can be assigned, but on a Proved + Probable + Possible Reserves basis, the project is economically viable, and a development decision has been made (e.g., adding compression, expanding facilities, offshore development of a structure delineated mainly with seismic with only limited well control).
- Only minor expenditure is required to develop the Possible Reserves and development is likely to proceed in the near future (e.g., behind-pipe zones in a well, which have Proved or Probable Reserves in another interval).
- Possible Reserves may be assigned to an accumulation that is being evaluated if Proved or Probable Reserves have been assigned to an adjacent part of the same accumulation that is not part of the evaluation for which a report is being prepared.

In all these situations, there should be an intention to develop the stand-alone Possible Reserves within a reasonable time. A report should contain an explanation of the reason for the assignment of stand-alone Possible Reserves.

1.3.8.2 Development and Production Status

1.3.8.2.1 Developed Reserves

Developed Reserves are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling and completing a well) to put the Reserves on production. The developed category may be sub-divided into Producing and Non-Producing.

- **Developed Producing Reserves** are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- **Developed Non-Producing Reserves** are those Reserves that either have not been on production or have previously been on production but are shut-in and the date of resumption of production is unknown.

1.3.8.2.2 Undeveloped Reserves

Undeveloped Reserves are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling and completing a well) is required to render them capable of production. They must fully meet the requirements of the Reserves category (Proved, Probable, Possible) to which they are assigned and expected to be developed within a limited time.

In multi-well pools, it may be appropriate to allocate total pool Reserves between the Developed and Undeveloped Sub-classes or to sub-divide the Developed Reserves for the pool between Developed Producing and Developed Non-Producing. This allocation should be based on the estimator's assessment as to the Reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

1.3.8.3 Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions are applicable to "individual Reserves entities", which refers to the lowest level that Reserves calculations are performed, and to "Reported Reserves", which refers to the highest-level sum (aggregated quantity) of individual entity estimates for which Reserves estimates are presented. Reported Reserves should target the following levels of certainty under a specific set of economic conditions.

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves.
- At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved + Probable Reserves.
- At least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved + Probable + Possible Reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various Reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, most Reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

ABBREVIATIONS

2U	best estimate scenario of prospective resources
Bcf	billions of cubic feet
COGEH	Canadian Oil and Gas Evaluation Handbook
COGEH Standards	Standards pertaining to the estimating and auditing of oil and gas reserves information included in the COGEH
FMI	formation microimager
km	kilometers
m	meters
Ma	mega annum
MD	measured depth
mGal	milligals
ms	milliseconds
NI 51-101	Canadian National Instrument Form 51-101
NSAI	Netherland, Sewell & Associates, Inc.
nT	nanotesla
NTG	net-to-gross ratio
OGIP	original gas-in-place
P05	5 percent confidence level
P50	50 percent confidence level
P95	95 percent confidence level
P_d	chance of development
PEL	Petroleum Exploration License
P_g	chance of geologic success
PHIE	effective porosity
ReconAfrica	Reconnaissance Energy Africa Ltd.
scf/rcf	standard cubic feet per reservoir cubic foot
SWE	effective water saturation
TVDSS	true vertical depth subsea
V_{sh}	shale volume

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DISCUSSION
DAMARA FOLD AND THRUST BELT PLAY AREA
PETROLEUM EXPLORATION LICENSE 73, KAVANGO BASIN, NAMIBIA

OVERVIEW

Netherland, Sewell & Associates, Inc. (NSAI) was engaged by Reconnaissance Energy Africa Ltd. (ReconAfrica) to estimate the prospective resources, as of March 31, 2023, to the ReconAfrica interest in certain opportunities subclassified as prospects located in the Damara Fold and Thrust Belt play area in the southwestern to south-central portion of Petroleum Exploration License (PEL) 73 in the Kavango Basin, northeastern Namibia. As of the date of this report, 9 prospects and 12 leads were identified and evaluated. This report is limited to our evaluation of the 9 prospects. As shown on the location map in Figure 1, PEL 73 is a large exploration license block covering over 25,000 square kilometers (over 6 million acres).

PEL 73 is currently in the early stages of hydrocarbon exploration. If a commercial discovery is made in PEL 73, ReconAfrica is entitled to a 25-year production license. The Kavango Basin, located to the east of the Owambo Basin, as shown in Figure 1, was identified by interpretation of gravity and high-resolution aeromagnetic data, as shown in Figures 2 and 3, respectively. No well or seismic data existed in the Kavango Basin until 2021, when two stratigraphic test wells, Mbambi 6-1 and Kawe 6-2, were drilled by ReconAfrica and logged various reservoir-quality clastic and carbonate zones of interest from Neoproterozoic to Permian age. The Makandina 8-2 well was drilled in 2022 and encountered the Karoo and pre-Karoo section penetrated by the Mbambi 6-1 and Kawe 6-2 wells. In 2021, an initial 2-D seismic survey covering 450 linear kilometers (km) was acquired over the license block. Subsequently, ReconAfrica acquired an additional 751 linear km of 2-D seismic data over the block in 2022 and over 1,300 linear km of 2-D seismic data over the block in early 2023. A map of the acquired seismic lines is shown in Figure 4. Interpretation of the available 2-D seismic lines identified two major plays: a Permian age rift basin (the Karoo Rift, the initial exploration target) and a large area of compressive structures (the Damara Fold and Thrust Belt). This report presents our evaluation of the Damara Fold and Thrust Belt play area, which has been subdivided into three sub-play areas: Sub-Play A, an area of low-relief structures; Sub-Play B, an area of high-relief structures; and Sub-Play C, an area of complex structures. The locations of the existing wells, currently identified sub-play areas with identified prospects and leads, and 2-D seismic lines are shown in Figure 5.

Two prospective carbonate intervals were identified in the Kawe 6-2 well within the Mulden and Otavi Groups of the Damara Supergroup, which dates from Neoproterozoic (Ediacaran) to early Paleozoic age. A stratigraphic column is shown in Figure 6. The play type analyzed in this report is the pre-Karoo Rift Damara Fold and Thrust Belt, which is an area of northwest-southeast-trending en-echelon anticlines bounded on the northeast by the major Karoo Rift fault. The western boundary of the area is the leading edge of the fold belt. The trend appears to continue to the northwest and south beyond current seismic data coverage.

GEOLOGY OF THE KAVANGO BASIN

Structure

The Kavango Basin's complex deformation history explains hydrocarbon trap development and is distinguished by three major phases of tectonic activity. Based on the study of the Owambo Basin (Hoak et al., 2014), these phases are as follows:

1. Katangan Orogeny (approximately 900 to 750 mega annum [Ma], or millions of years)
2. Damara Orogeny (approximately 580 to 530 Ma)
3. Karoo Rifting (approximately 300 to 130 Ma)

Phase 1 is characterized by the rifting of the Rodinia supercontinent. During this time, metamorphic basement rocks formed into north-northwest-striking horsts and grabens. These horst-and-graben rift features and associated faults became the foundation for later structures that may have petroleum potential. Known as the Katangan Orogeny, this incipient Precambrian rifting episode occurred from approximately 900 to 750 Ma.

Phase 2 is associated with the collision of the Kalahari craton from the south and the Congo craton from the north along the Damara-Mwembeshi fault zone. This major collision event is known as the Damara Orogeny and consisted of two collision stages. The initial collision along the Kaoko Belt resulted in east-west crustal shortening between 580 and 550 Ma and is evidenced by northwest-southeast-trending structures. Later, shortening during the period from 550 to 530 Ma rotated to a north-south direction, which created northeast-southwest-trending structures in the Damara Belt. During these collision events, significant right- and left-lateral movement activated extension and inversion along major fault zones, which resulted in thrust and wrench structures across the basin, as shown in Figure 7.

The fold and thrust belt structures identified in this study are predominantly northwest-southeast trending, suggesting that they were initiated during the early Damara Orogeny. The interpreted basement structure in the Damara Fold and Thrust Belt area deepens to the west.

Phase 3 corresponds to a second phase of rifting, which allowed for Karoo sediment infill deposition. The initial Permian age Karoo rift-fill episode of the Kavango Basin experienced early extension with significant thicknesses of sediments deposited, including the Dwyka and Ecca Formations. This was followed by a more stable period during the Mesozoic when the Upper Karoo Omingonde and Etjo Formations were blanketed atop the Lower Karoo. Later, metamorphism and intrusion of massive dolerite sills and dyke swarms (those related to the Cretaceous opening of the South Atlantic Ocean) occurred, with major dyke exposures evident in some parts of northwestern Namibia, as shown in Figure 8.

Stratigraphy

Reinterpretation of the Kavango Basin high-resolution aeromagnetic data by Earthfield Technology, LLC indicates that up to 30,000 feet (approximately 9,150 meters [m]) of sediment may have accumulated in the deeper parts of the basin (Cathey, 2020), as shown in Figure 3. The complex structural history of the basin has significant influence on the basin stratigraphy, including several periods of uplift and erosion, which resulted in multiple unconformities that bookend key stratigraphic intervals. We have referenced the stratigraphic column by Hoak et al. (2014) (Figure 6) for the Owambo Basin as an initial interpretation of the Kavango Basin stratigraphy, which has a related structural history. The three wells drilled by ReconAfrica in the Kavango Basin were drilled on shallow structural features with a deepest penetration depth of 2,734 m measured depth (MD) without encountering basement. Without an offstructure well, basement intersection, or well test of the deep section observed on seismic data to confirm the stratigraphy and lithology of the Kavango Basin, we have interpreted the stratigraphic section based on analogy to the Owambo Basin work.

Basement

Basement in northern Namibia consists of metamorphic rocks, including granite from several formations, which are generally 1 billion years old or older, capped by metamorphosed sandstones and volcanics of the Khoabendus Formation and all of Mesoproterozoic age.

Neoproterozoic – Damara Supergroup

The Damara Supergroup contains the Nosib, Otavi, and Mulden Groups. The basal Nosib Group, deposited during early rifting associated with the breakup of Rodinia (Miller, 2008), unconformably overlies basement, and the Otavi Group, deposited after the Phase 1 Katangan Orogeny, unconformably overlies the Nosib Group. The Mulden

Group unconformably overlies the Otavi Group and was deposited after the Phase 2 Damara Orogeny. The Mulden Group sediments truncate in early Paleozoic time, approximately 530 Ma, by a major unconformity associated with nondeposition from approximately 530 to 300 Ma.

The Nosib Group contains the Austerlitz and Naauwport Formations and comprises interbedded continental and marine sandstones with some shales capped by volcanics.

Otavi Group carbonates and other sediments were deposited on a stable platform. Initial deposition was primarily glacial tillites of the Chuos Formation, which were deposited on the Katangan unconformity surface. The tillite deposits were covered with shallow-marine dolomites and shales of the greater Abenab Formation and capped with glacial marine sandstones and Chaub Formation glacial tillites. The Abenab Formation shallow-marine sediments contain algal mound buildups, oolitic shoals, and multiple unconformities with potential karsting in the carbonates, which could have reservoir potential. The shales in the Abenab have source rock and seal potential.

The Chaub tillite top and laterally equivalent Abenab Formation top are an unconformity surface that is the base of the greater Tsumeb Formation. The Tsumeb contains another alternating sequence of shallow-marine basinal shales and carbonates, including algal mounds and buildups as well as oolitic banks. The algal carbonate buildups and oolite banks are potential reservoirs coupled with basinal shales that may have source potential. The sediments of the Tsumeb Formation are truncated by a major unconformity related to the Damara Orogeny.

The Mulden Group, the uppermost group in the Damara Supergroup, was deposited after the Damara Orogeny. Initial sediments in the section are shallow-marine basinal shales of the Tschudi Formation with potential source and seal capacity. A marine regression occurred at the top of the Tschudi Formation, creating local areas of nondeposition. The regression resulted in continental conglomerates, sands, and shales being deposited as the Kombat Formation. The Kombat Formation continental section is truncated by an unconformity.

The Owambo Formation unconformably overlies the Kombat section. Initial sediments of the Owambo are marine black shales with possible source and seal potential. Moving upward in the Owambo, the depositional environment is such that the section above the black shale transitions from marine limestones, shales, and sandstones to continental sand and shale sections. The Owambo section is truncated by an unconformity, which was created by an approximately 240-million-year period of nondeposition from the early Paleozoic to the late Carboniferous.

Paleozoic and Mesozoic – Karoo Supergroup

During Phase 3, the Karoo Supergroup was deposited between approximately 300 and 115 Ma, beginning during the late Carboniferous to early Permian period and ending in the Late Cretaceous. Karoo sedimentation initiated as Gondwana tillites and finished with continental sediments, which are truncated by an unconformity associated with faulting and uplift related to rifting of the South Atlantic Ocean.

The initial Karoo sediments are basal glacial tillites of the Dwyka Formation of late Carboniferous to early Permian age. The tillites transition into continental sandstones, shales, claystones, and coals with a more prominent shale at the top of the section called the Dwyka shale. Some reservoir potential may exist in the sands of the Dwyka section, while the coals may have some gas source potential. The top of the Dwyka is an unconformity.

The Ecca Formation unconformably overlies the Dwyka Formation. Initial sediments of the Ecca Formation are likely cratonic basin marine shales and turbidite complexes that progress upward into deltaic sandstones, lacustrine shales, and coals and are subsequently covered by fluvial and aeolian deposits of the Omingonde Formation. These continental mudstones with limited interbedded sandstones and conglomerates of the Ecca Formation are capped by a continental coal-bearing sandstone and shale interval. This coaly interval is described as the Tavrede Formation in the literature. We have included the Tavrede in the Omingonde.

Overlying the Omingonde Formation is the Etjo Formation, which primarily comprises aeolian claystones with significant volumes of volcanics that were intruded approximately 130 Ma. The Etjo is truncated by a Late Cretaceous unconformity and the Rooiwal basalts. The Rooiwal basalts are encountered as both intrusive and extrusive deposits.

Late Cretaceous and Cenozoic – Kalahari Formation

The Kalahari Formation comprises unconsolidated sands. The Kalahari sands cover the subsurface structures of the Kavango Basin formed by the two orogenic phases.

PETROLEUM SYSTEM

While the first three wells demonstrated a range of oil and gas shows, an economic petroleum system has not been successfully demonstrated to date in the Kavango Basin. Potential petroleum systems for the Damara Fold and Thrust Belt may occur in the Otavi and Mulden Groups and will likely be dry gas with some potential for gas liquids. The recently drilled Makandina 8-2 well captured gas samples from the pre-Karoo section. As presented in mud gas isotope and compositional analysis reports prepared by GeoMark Research, Ltd., the samples contained thermogenic gas (also known as methane) and some limited hydrocarbon gas liquids.

Trap Integrity

The traps currently identified in the Damara Fold and Thrust Belt area of the block are all structural. The fold and thrust area is currently in the early stages of exploration and is covered by 1,131 linear km of 2-D seismic data (of the approximately 2,700 linear km of 2-D seismic data acquired in total). Structural traps offer the best opportunity for trap integrity, and the current 2-D seismic interpretation has identified compressional structures in the Damara Fold and Thrust Belt associated with thrust faulting and potential wrench faulting of the Mulden and Otavi Groups during the Damara Orogeny.

The Damara Fold and Thrust Belt area, as identified on the available 2-D seismic interpretation, has been subdivided into three sub-play areas from west to east: Sub-Play A, an area of low-relief structures; Sub-Play B, an area of high-relief structures; and Sub-Play C, an area of complex structures.

Sub-Play A

Sub-Play A, located west-southwest of the Mbambi 6-1, Kawe 6-2, and Makandina 8-2 wells and west of Sub-Play B, consists of well-defined low-relief structures created by thrusts and back thrusts. The structures of the Damara Fold and Thrust Belt in this area are simple and generally smaller and low relief. The vertical relief of most of these structures, as seen on the 2-D seismic data, appears to be less than 100 milliseconds (ms). Due to the simpler structuring and fewer apparent faults coupled with the deeper crests of the structures, the maximum extent of the interpreted shallow (Mulden) section has been preserved across the structural crests. Principal objectives should be the Upper Mulden, Lower Mulden, and Otavi intervals across all anticlines. Two prospects and five leads have been identified to date in the Sub-Play A area.

Sub-Play B

Sub-Play B, located south-southwest of the Mbambi 6-1, Kawe 6-2, and Makandina 8-2 wells and east of Sub-Play A, consists of well-defined high-relief structures created by westward-verging thrust faults. The structures of the Damara Fold and Thrust Belt in this area are generally larger for westward thrusts and smaller with lower relief for back thrusts. The vertical relief of some of these structures, as seen on the 2-D seismic data, may reach 500 ms. Due to the generally less-complicated structuring and fewer apparent faults coupled with the deeper crests of the structures, the majority of the interpreted shallow (Mulden) section has been preserved across the structural crests. Principal objectives should be the Upper Mulden, Lower Mulden, and Otavi intervals across all but the highest anticlines. Five prospects and three leads have been identified to date in the Sub-Play B area.

Sub-Play C

Sub-Play C, located south-southeast of the Mbambi 6-1, Kawe 6-2, and Makandina 8-2 wells, consists of complex structures that are generally the shallowest structures of the Damara Fold and Thrust Belt. These structures were created by multiple thrust faults potentially with some translational movement. The vertical relief of some of these structures, as seen on the 2-D seismic data, may reach 700 ms. Due to the large amount of structuring and the shallow crests of the structures, the majority of the interpreted shallow (Mulden) section has been eroded across the structural crests. Principal objectives should be the Lower Mulden and Otavi intervals. Two prospects and four leads have been identified to date in the Sub-Play C area.

A table listing the currently identified prospects and leads for the Damara Fold and Thrust Belt area is presented in Figure 9.

Reservoir

The Kawe 6-2 well identified two potential carbonate reservoir intervals within the Mulden Group and the older Otavi Group containing 34 m of net reservoir with average porosity of 8 to 9 percent and maximum porosity of 17 percent. Water saturations in these intervals indicate the potential presence of hydrocarbons. A third, shallower carbonate interval (46-m section) was also encountered but was unable to be logged in the open hole.

In the Kavango Basin, the Damara Supergroup comprises the Nosib, Otavi, and Mulden Groups, which all contain formations with potential reservoirs. The basal sands of the Austerlitz Formation of the Nosib Group deposited on basement have reservoir potential; however, the three wells drilled to date by ReconAfrica on the block failed to encounter this zone. Prospective intervals of the Otavi Group include multiple carbonate formations within the lower Damara Abenab Formation and upper Damara Tsumeb Formation as well as additional clastic tillites of the Chuos and Chaub Formations, which are similar to the tillites of the Dwyka Formation of the Karoo Supergroup. In the Owambo Basin, the Huttenberg, the shallowest member of the Tsumeb Formation of the upper Otavi Group, was penetrated by the Etosha 5-1A well, which encountered a carbonate-rich section. The recorded well logs indicated potential reservoir parameters for the drilled 230-m section including a net-to-gross ratio (NTG) of approximately 25 percent and an average porosity of 7 to 8 percent for the net interval (OPIC, 1990).

Separated from the Otavi by the major Damara Orogeny unconformity (50-million-year age differential), though still within the Damara Supergroup, multiple sands deposited in the continental sediments of the Mulden Group may have reservoir qualities. In the Mulden Group, the Kombat and Owambo are two formations that contain potential reservoir-quality rock. In the Owambo Basin, the upper Owambo Formation was described as a 380-m-thick siliciclastic interval with a NTG of 50 to 60 percent and porosity ranging from 15 to 20 percent (Momper, 1982; Miller, 2008). Below the upper Owambo, a black shale member was encountered above a lower Owambo siliciclastic section. The lower Owambo section has poorer reservoir characteristics than the upper Owambo. The lower Owambo is a 200-m-thick interval with a NTG of 30 percent and an average porosity approaching 15 percent.

Seal

The potential seals for the various reservoirs in the Otavi Group may be the platform carbonates and shales of the Abenab and Tsumeb Formations. In the Mulden Group, shallow-marine shales of the Tschudi, Kombat, and Owambo Formations all have sealing potential but may be areally restricted. The black shale marker in the lower Owambo Formation is about 100 m thick (Miller, 2008), is widely distributed in the Owambo Basin, and may have the best seal capacity of all intervals. This shale marker has yet to be documented by a well penetration in the Kavango Basin. Seal potential in the Karoo is limited.

Source

Kavango Basin source rocks are expected to be the same shales as those encountered in the Owambo Basin. The best potential source rocks identified to date in the Owambo Basin are the black shales of the middle Owambo Formation and shales of the Otavi Group. Additional source potential may exist in the shallow-marine shales in the Mulden Group. Total organic carbon values reach up to 9 percent in the Otavi Group outcrops in the Owambo Basin (Bechstädt et al., 2009). The principal source rocks are expected to be shales; however, algal mudstones and limestones deposited in the Abenab and Tsumeb Formations may have excellent source potential.

Coals in the Karoo Supergroup may have hydrocarbon-generative potential; however, they are most likely to be gas generative. Thermogenic, dry gas was identified from active gas seeps on the block; however, the source of the gas was not identified.

Timing and Migration

Worldwide Geochemistry, LLC analyzed hydrocarbon mud gas shows in the Kawe 6-2 well. Three hydrocarbon-bearing zones were identified in this analysis. These zones all have traces of light oil and gas, suggesting that the unidentified source rocks have obtained a maturity level sufficient to generate light oil and gas. The only well information is at shallow depths (above 2,000 m MD) on structural highs, precluding a detailed analysis of the basin's thermal history and consequent hydrocarbon generation history. The current drilled well locations are on the structural highs and do not provide an optimum data set to determine source rock quality and maturation level (Jarvie, 2021).

PETROPHYSICS

NSAI performed an independent petrophysical evaluation of the Kawe 6-2 well using available cased-hole and open-hole well log data, routine and special core analyses from rotary sidewall cores, mudlogs, and formation microimager (FMI) data and analysis. Well log analysis was performed, integrating the core and mudlog mineralogy data, core porosity, and core electrical properties data for calibration of the petrophysical modeling parameters.

The well had good-quality open-hole log data sets with standard formation evaluation logs, including spectral gamma ray, bulk density, sonic, neutron porosity, and resistivity logs. Over the interval from 810 to 1,250 m MD in the Kawe 6-2 well, open-hole density and neutron logs were unavailable. In this section, cased-hole formation density and neutron logs were run and used for the evaluation. These cased-hole log measurements are regarded as having larger uncertainty than the open-hole log measurements. In the cased-hole logs, bulk density log quality was suspect because of borehole rugosity in the shallow intervals logged in the Kawe 6-2 well; therefore, bad-hole flags were created to eliminate the suspect data from analysis.

Clastic and carbonate rocks are present in the well. Coals described in the mudlogs for the Kawe 6-2 well were identified on the well logs using a bulk density log cutoff. Multiple minerals are present in the carbonate sections, including clay, quartz, dolomite, calcite, and anhydrite. The core X-ray diffraction and mudlog data were used in combination to calibrate a mixed-lithology log model through the carbonate intervals that estimated the individual volume of shale, limestone, dolomite, and anhydrite. Neutron porosity and bulk density crossplot methods were used for the complex carbonate lithology model, and the results were consistent with lithology indications from available photoelectric logs. Grain density was estimated from the lithology estimates, and total and effective porosity were estimated from the bulk density logs. Formation water resistivity was determined using Pickett Plot analysis, and standard electrical property values were used to estimate water saturation. In intervals where core electrical property data were available, averages of these core values were used in the water saturation modeling.

Well log analysis results indicated several potential reservoir zones in the Kawe 6-2 well in both the clastic and carbonate lithologies. The identified Karoo sands were found in thick intervals with good porosity. FMI logs were reviewed in the carbonate zones of interest for indication of the presence of fractures and fracture porosity. Because of the complex nature of many carbonate pore systems, mercury injection capillary pressure data from available sidewall cores were used to evaluate the reservoir potential of these zones.

Estimates of net thickness, porosity, and water saturation were made over the intervals identified as potential reservoir rock using a 40 percent shale volume cutoff and a 10 percent effective porosity cutoff in the clastic zones and a 20 percent shale volume cutoff and a 5 percent effective porosity cutoff in the carbonate zones.

The Kawe 6-2 well log is shown in Figure 10, and petrophysical results are summarized in the following table:

Well/Zone	Zone Type	Top (m MD)	Base (m MD)	Top (m TVDSS)	Base (m TVDSS)	Gross Thickness (m)	Net Reservoir Thickness (m)	V_{sh} (decimal)	PHIE (decimal)	SWE (decimal)
Kawe 6-2										
Mulden	Carbonate	1,077	1,250	45	-128	172.6	46.4	0.11	0.12	0.55
Otavi	Carbonate	1,338	1,357	-216	-235	18.8	5.3	0.08	0.09	0.56
Otavi	Carbonate	1,881	1,979	-756	-853	98.1	29.2	0.06	0.08	0.61

EVALUATION METHODOLOGY

Exploration opportunities are subclassified as prospects or leads depending upon the available data and degree of interpretation. A prospect is considered to have enough data and interpretation such that it is currently ready to drill. A lead has insufficient data or interpretation to adequately identify a drillable structural closure and/or petroleum system at the current time.

We conducted independent assessments of the opportunities, most with multiple potential target zones. We considered the data and interpretations provided by ReconAfrica. We reviewed the 2-D seismic data for all opportunities identified by ReconAfrica and determined the areas to be input into our assessment. In addition, we determined our subclassification of each opportunity as a prospect or lead based upon the available seismic coverage of each opportunity. We reviewed each opportunity and performed a geologic risk assessment based on the work of Otis and Schneidermann (1997). We used probabilistic methods to estimate undiscovered original gas-in-place and prospective gas resources. Each opportunity was treated independently in our analysis and, given the lack of available data, no dependencies were taken into account between potential target zones in a prospect or lead.

We reviewed and independently mapped the 2-D seismic data to define potential structural trapping geometries and to assess risks and uncertainties. Potential areas were calculated for each opportunity using the 2-D seismic lines as a basis for estimating areal closure based on structural and fault spill points. We estimated gross thicknesses of depositional sequences from seismic two-way-time interpretations and made depth-conversion estimates using the Kawe 6-2 vertical seismic profile data.

We estimated probabilistic uncertainty ranges for geometric factor, net thickness, porosity, water saturation, and formation gas volume factor and used these ranges as inputs for a Monte Carlo simulation to estimate the potential undiscovered in-place volumes. We then applied gas recovery factors to these estimates of undiscovered in-place volumes to estimate recoverable prospective gas volumes. The probabilistic uncertainty ranges were determined separately by sub-play area (A, B, and C) and potential target zone (Mulden [upper or lower Owambo] and Otavi).

A table of area by location and target is shown in Figure 11, and a table of selected reservoir parameters is shown in Figure 12.

Available data for PEL 73 provided by ReconAfrica included the following:

- IHS Markit Kingdom project for the license containing, but not limited to, the following:
  - Proposed opportunities.
  - Wells and well data such as headers, directional surveys, logs (raw and processed), and formation tops.
  - Potential fields data (aeromagnetics and gravity).
  - 2-D seismic data (in time and depth) and horizon interpretations.
- Core data and analyses.
- All available petroleum system, regional geology, exploration potential, and opportunity description reports.

RISK ASSESSMENT

The prospective resources included in this report represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made; prospective resources have both an associated chance of discovery and a chance of development, which together define the chance of commerciality.

The chance of discovery was estimated using a geologic risk assessment for these prospects, as discussed in subsequent paragraphs. We conducted the geologic risk assessment for the ReconAfrica-identified prospects using a four-component methodology based on Otis and Schneidermann (1997) to measure the probability of geologic success (P_g). Geologic risk assessment addresses the probability of success for discovering hydrocarbons without regard to commerciality. We recognize the primary risk elements as (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Because of the subjective nature of geologic risk assessment, any such assessment is highly dependent on the experience of the evaluators, the data available to define each prospect or lead, the regional data available to describe reservoir and production characteristics, and the historical local and regional hydrocarbon discovery success rates. Otis and Schneidermann define a P_g greater than 0.50 as very low risk, a P_g between 0.50 and 0.25 as low risk, a P_g between 0.25 and 0.125 as moderate risk, a P_g between 0.125 and 0.0625 as high risk, and a P_g below 0.0625 as very high risk exploration opportunities. Our assessments of P_g by location and target are shown in Figure 13.

Development risk assessment addresses the chance of development (P_d) given geologic success; this risk analysis is conducted based on the associated economic and development related factors (development plan, production forecasts, markets, facilities, capital and operating costs, product prices, approvals, etc.). Typically, one of the primary components of development risking is associated with the chance that the discovery will be larger than the minimum economic field size. For the purposes of this assessment of development risk, we have considered a more robust set of elements to be (1) financial considerations, including the chance of exceeding the minimum economic field size, (2) access to sales markets, (3) development plan approval, and (4) government and regulatory approvals. Development risking is subjective and is highly dependent on access to market information, regional economic conditions, operator intent and commitment to develop, and geopolitical initiatives. For the purposes of our evaluation of these opportunities as of March 31, 2023, P_d includes all four of these elements. Our assessment of P_d by location is shown in Figure 13. It should be understood that there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

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

PROSPECTIVE RESOURCES

We estimate the unrisked and risked gross (100 percent) prospective gas resources and the unrisked and risked company gross prospective gas resources to the ReconAfrica interest in these prospects, as of March 31, 2023, to be:

Best Estimate (2U) Prospective Gas Resources (Bcf)					
Unrisked			Risked[1]		
Gross (100%)	Company Gross	Net[2]	Gross (100%)	Company Gross	Net[2]
14,548.8	13,093.9	12,439.2	777.6	699.9	664.9

Note: Prospective resources are the arithmetic sum of multiple probability distributions.

(1) These estimates are based on unrisked prospective resources that have been risked for chance of discovery and chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

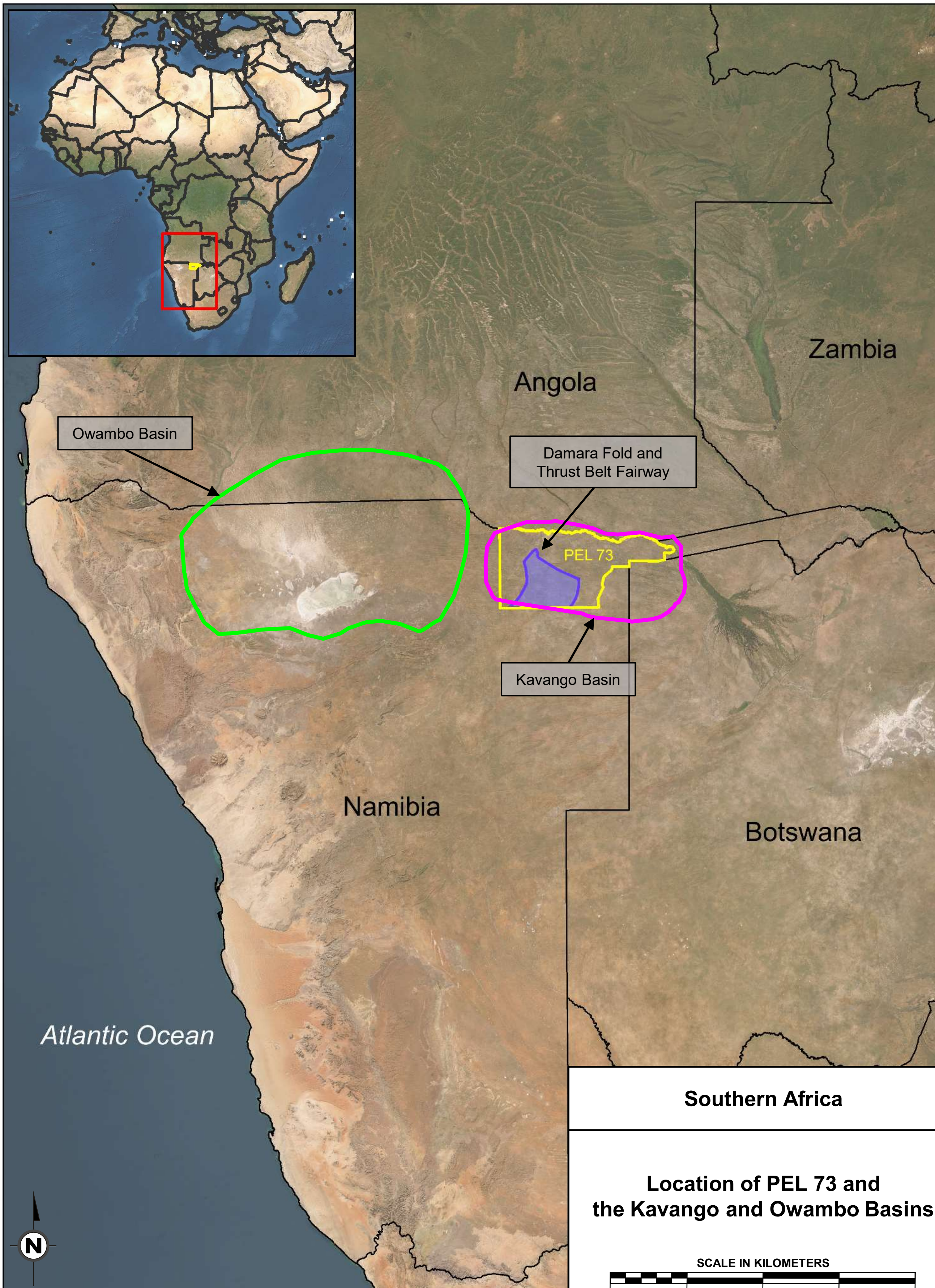
(2) Net prospective resources are after royalty deductions.

Gas volumes are expressed in billions of cubic feet (Bcf) at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. As requested, low estimate and high estimate prospective resources have not been included in this report. A summary table of undiscovered in-place volumes and unrisked and risked gross (100 percent) prospective gas resources by location and target are shown in Figure 13. For the purposes of this report, the volumes and parameters associated with the best estimate scenario of prospective resources are referred to as 2U. The 2U prospective resources have been aggregated beyond the prospect level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation. Statistical principles indicate that the arithmetic sums of multiple estimates may be misleading as to the volumes that may actually be recovered.

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

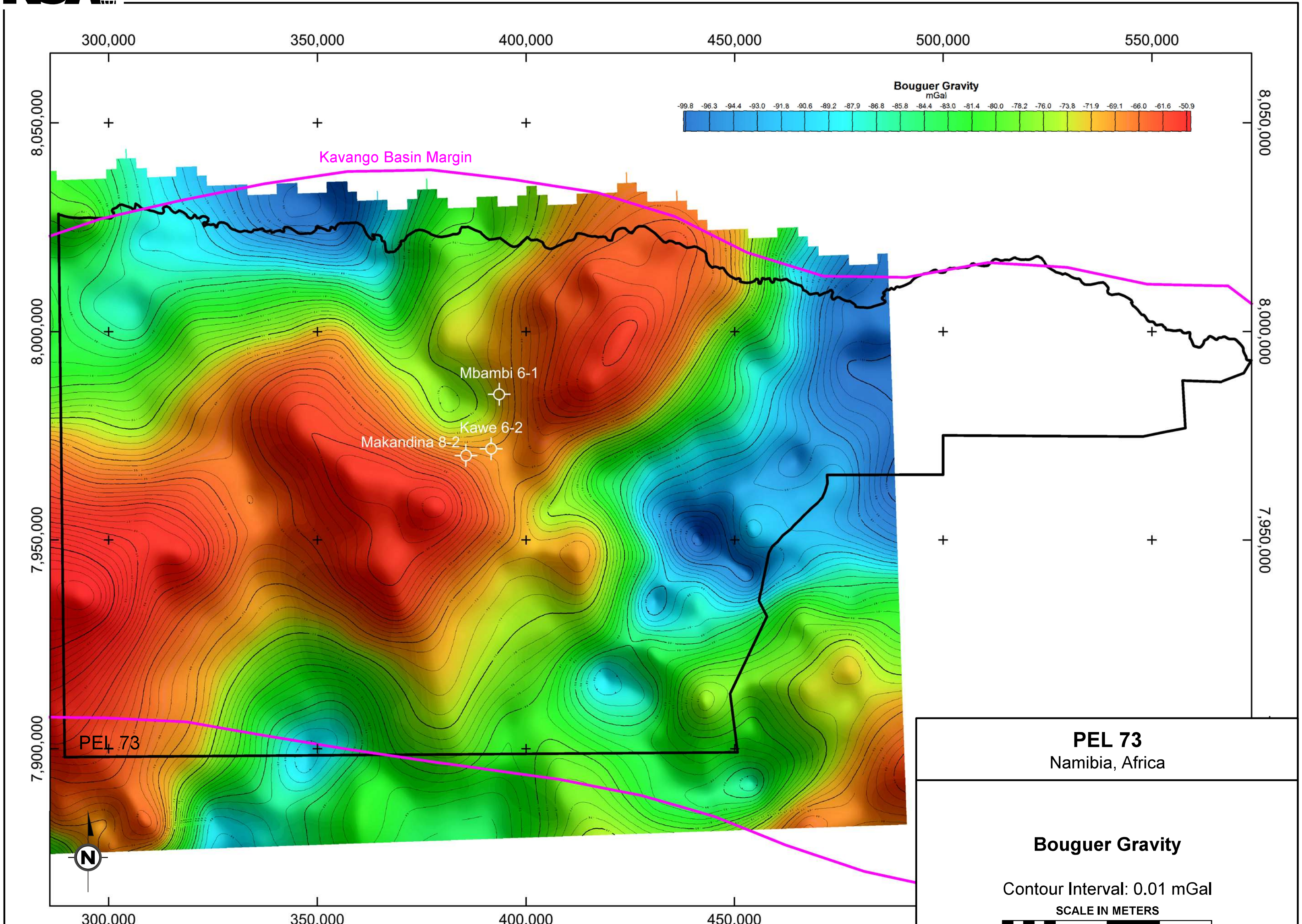


Southern Africa

Location of PEL 73 and the Kavango and Owambo Basins

SCALE IN KILOMETERS
0 125 250 375 500

NETHERLAND, SEWELL & ASSOCIATES, INC.



Adapted from a figure provided by Earthfield Technology, LLC.

Figure 2

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

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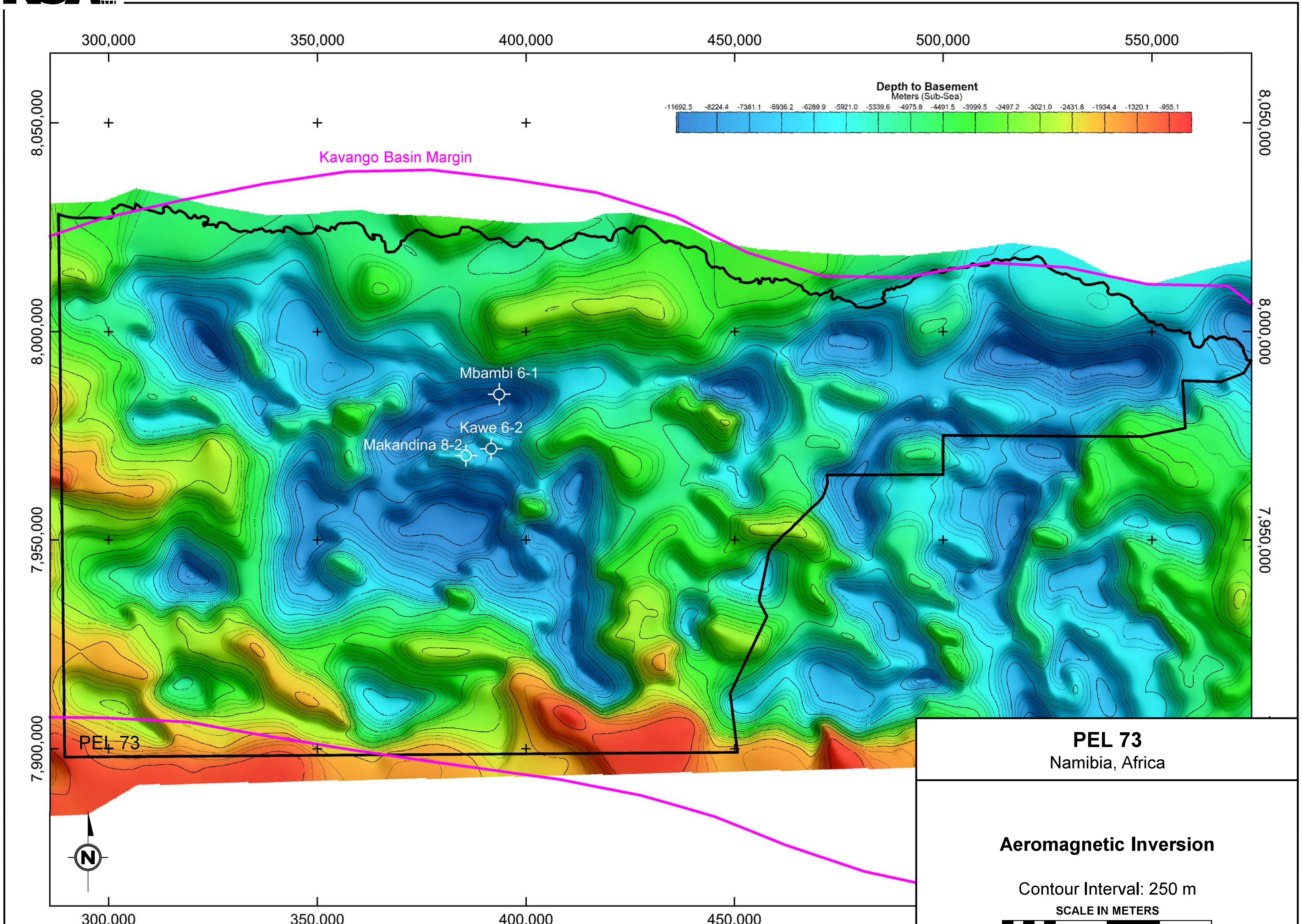


Adapted from a figure provided by Earthfield Technology, LLC.

Figure 3

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

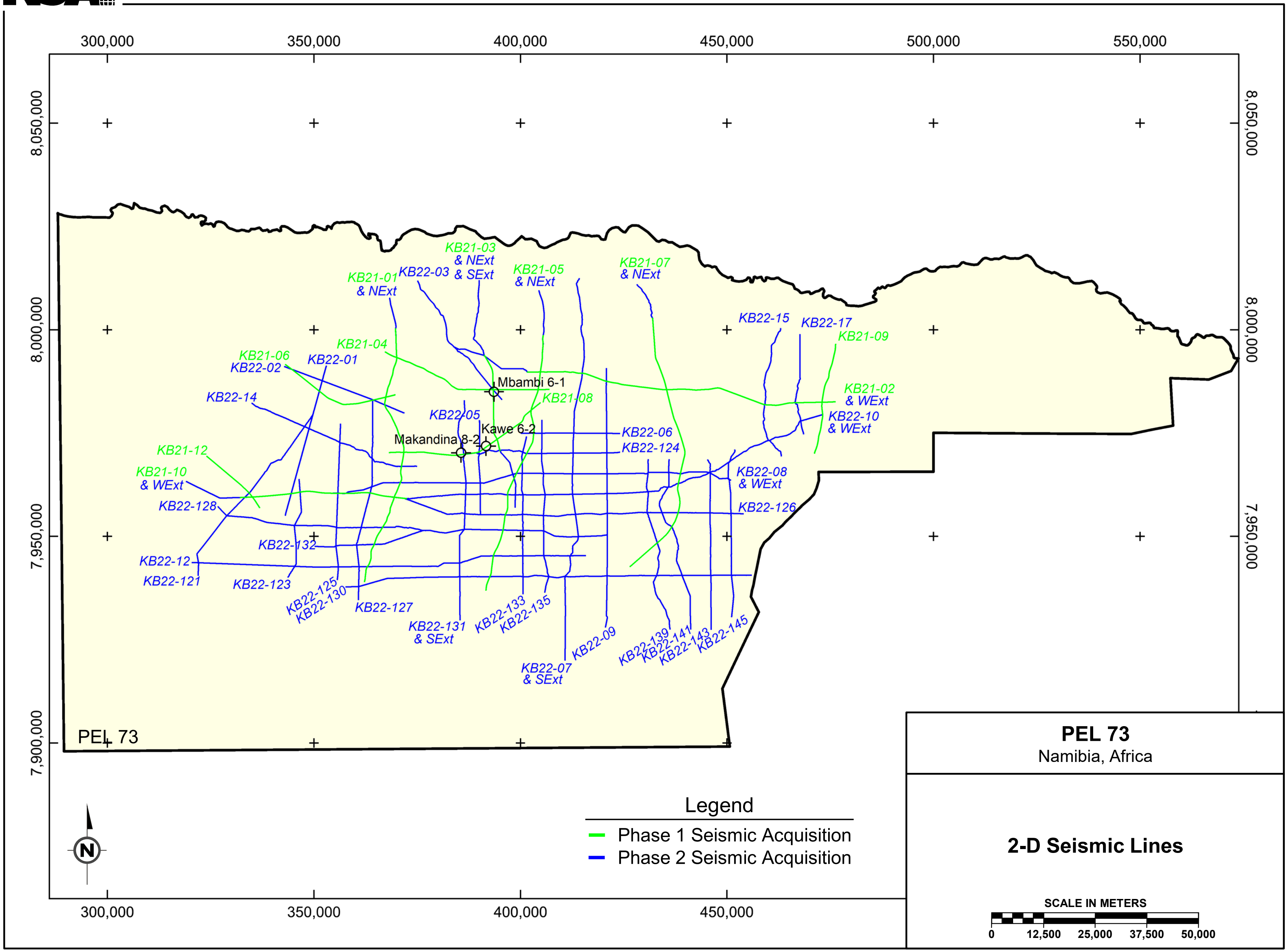
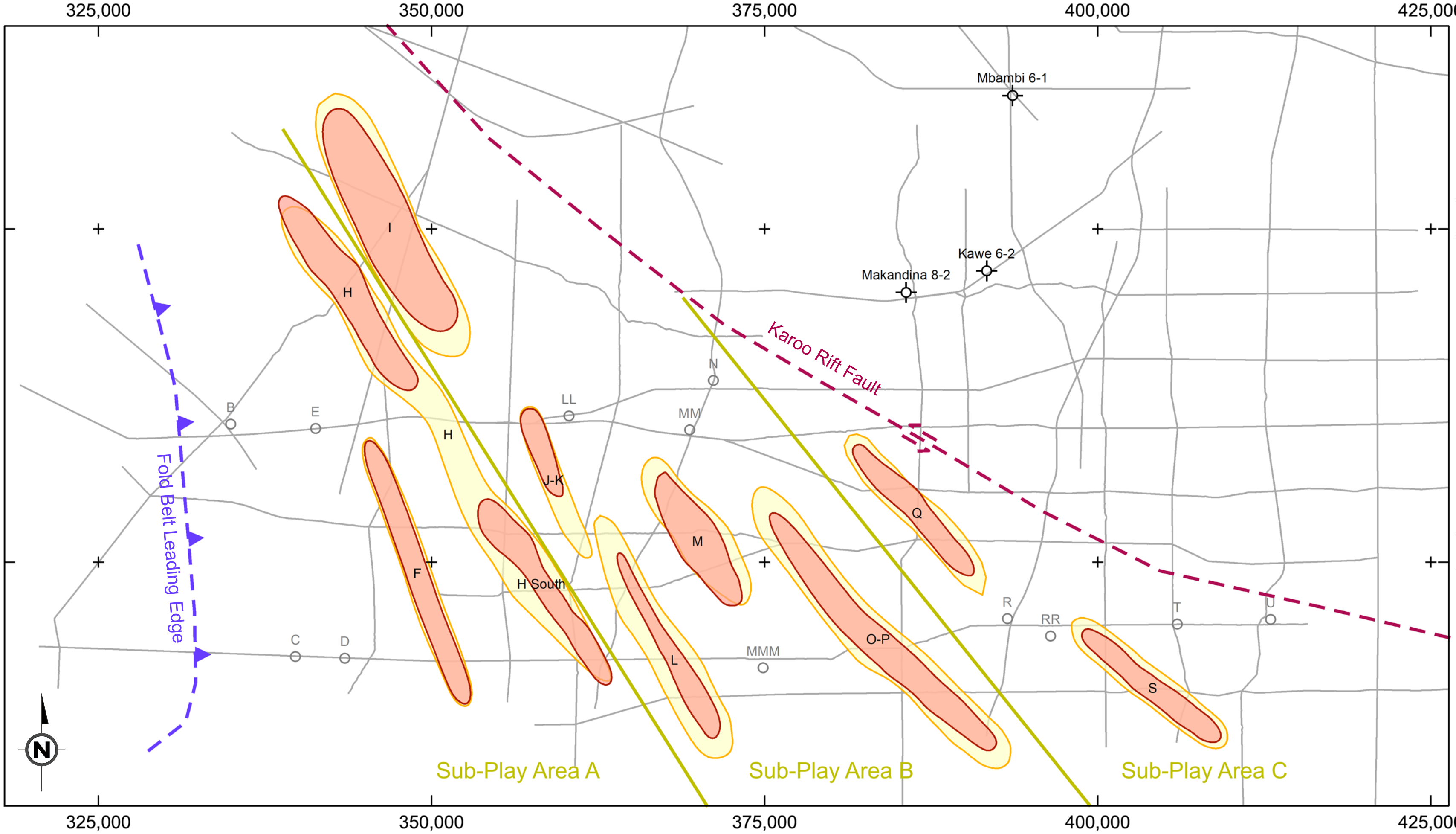


Figure 4

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



PEL 73
Namibia, Africa

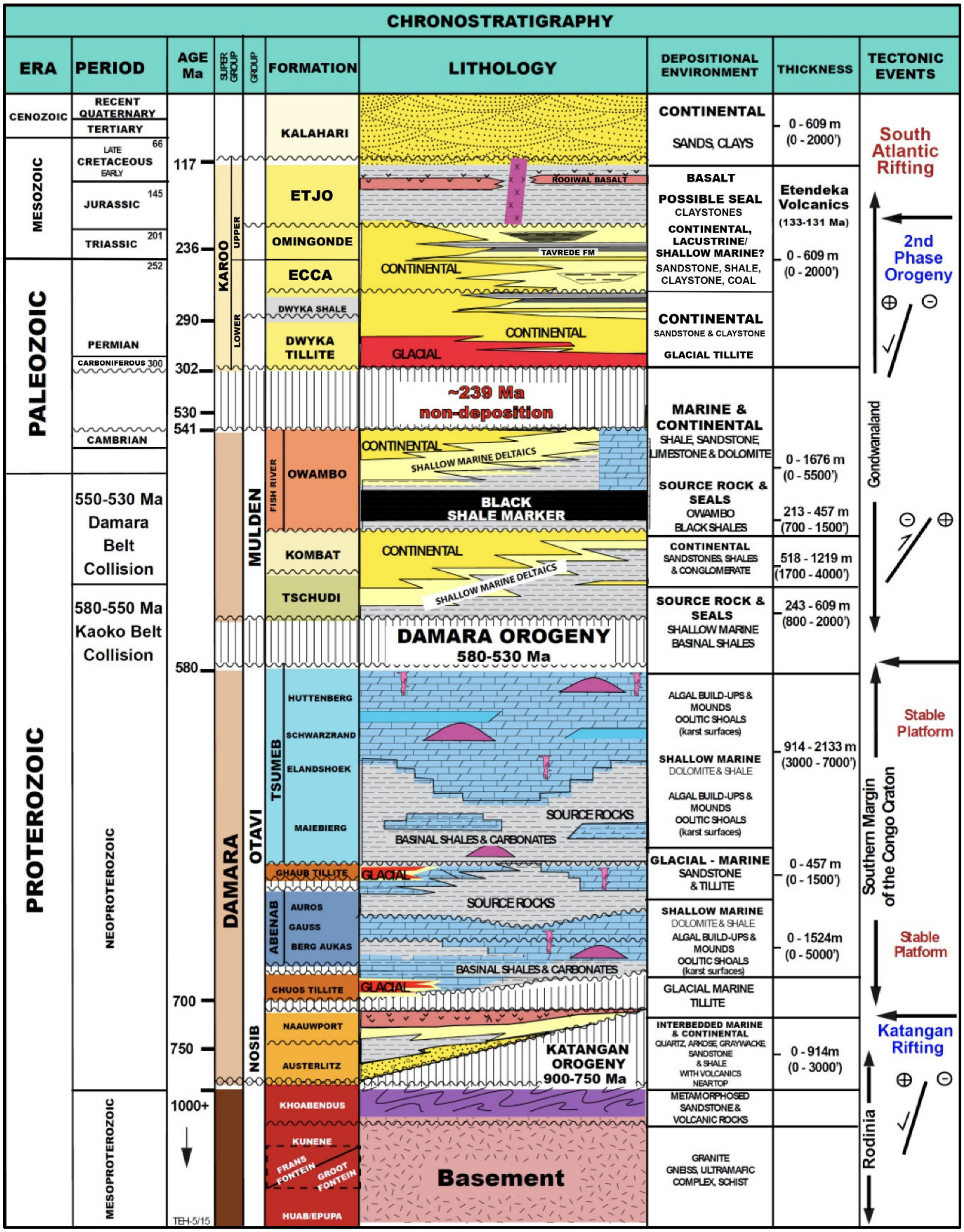
Fold and Thrust Belt Opportunities for Sub-Play Areas Mulden and Otavi Groups

SCALE IN METERS
0 6,250 12,500 18,750 25,000

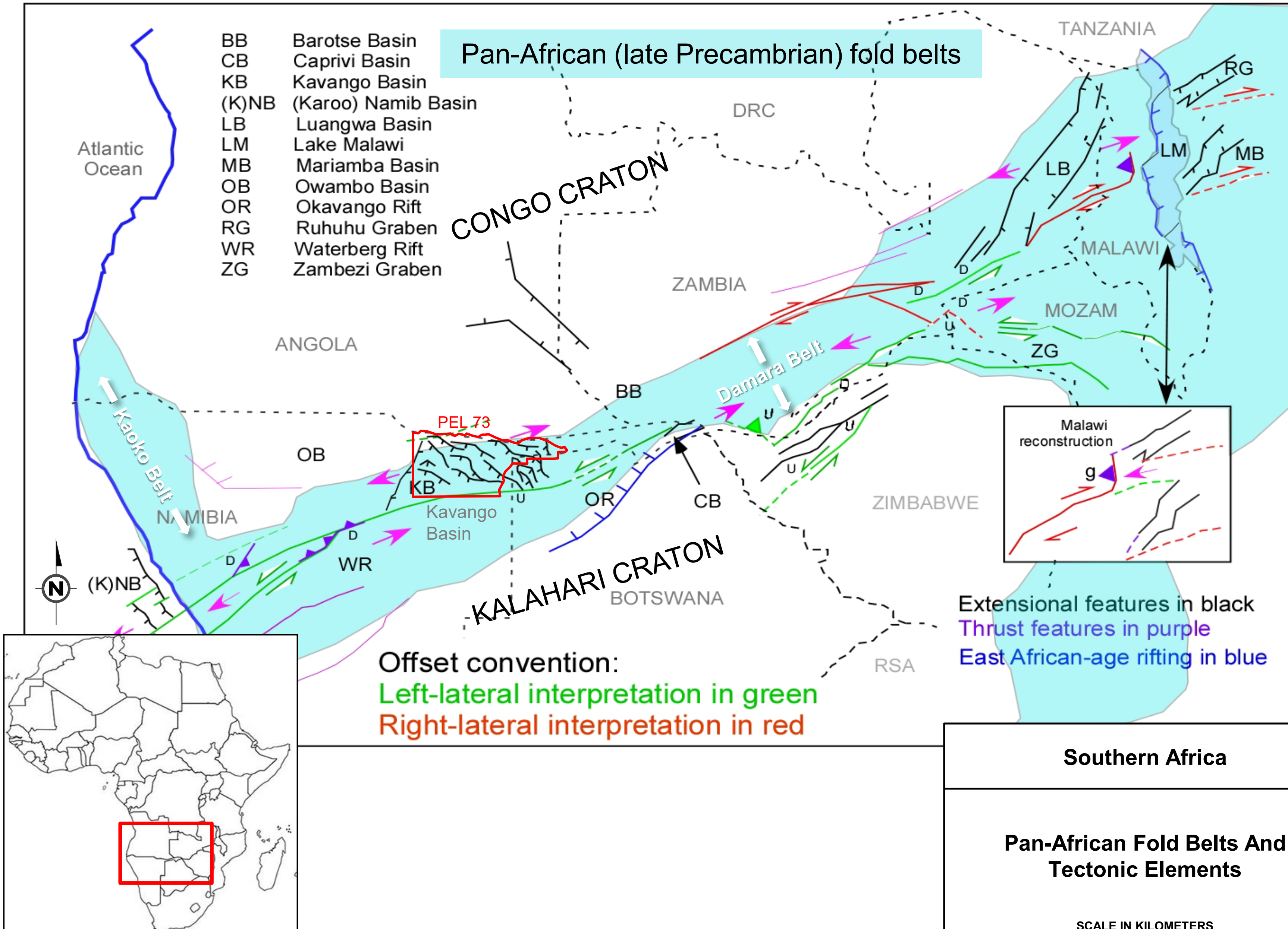
Figure 5

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

Chronostratigraphic Column
Kavango Basin, Onshore Namibia



Adapted from Hoak et al., 2014.



Adapted from a figure provided by Reconnaissance Energy Africa Ltd.

Southern Africa

Pan-African Fold Belts And Tectonic Elements

SCALE IN KILOMETERS
0 125 250 375 500

Figure 7

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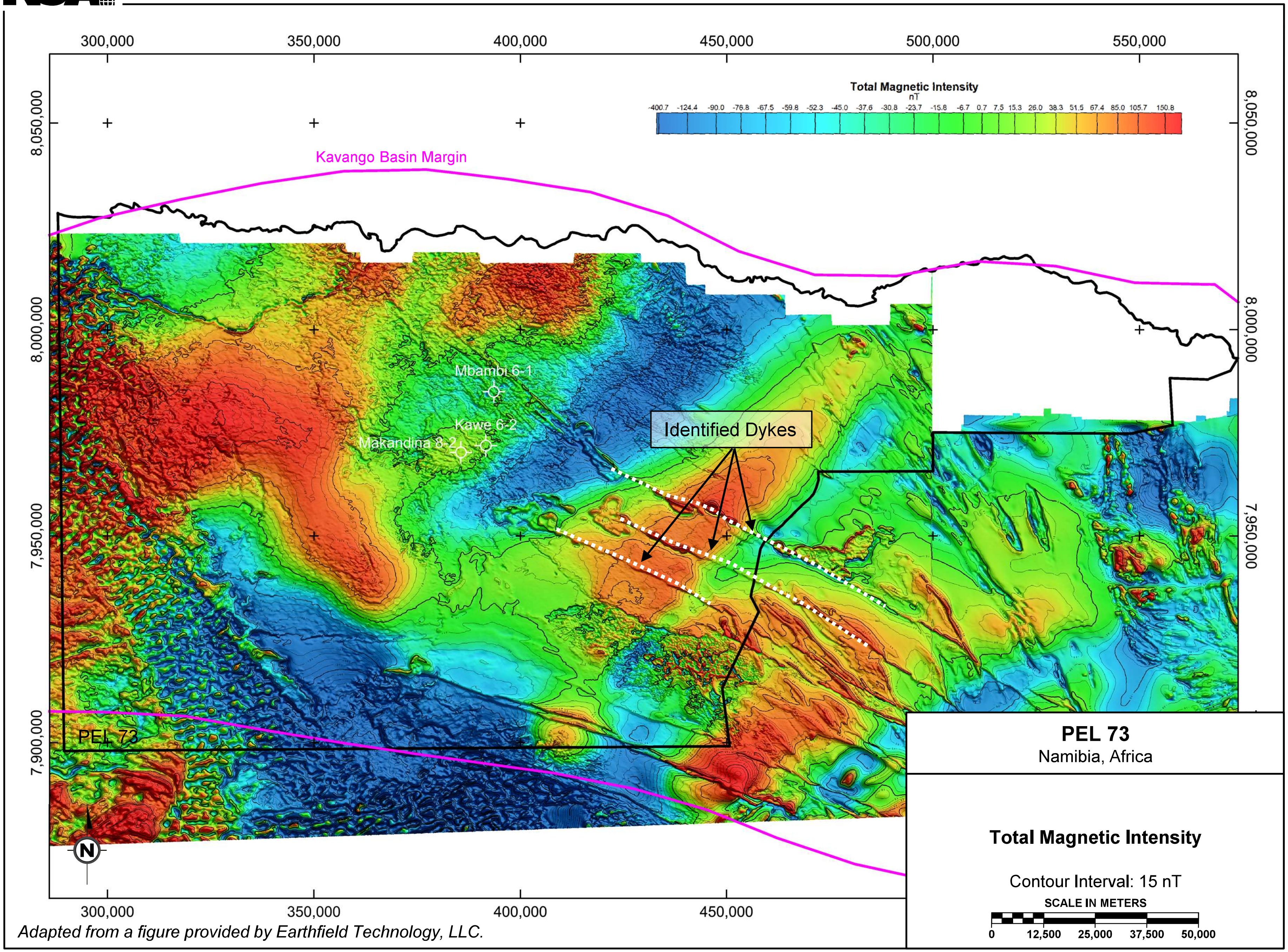
& ASSOCIATES, INC.



Adapted from a figure provided by Earthfield Technology, LLC.

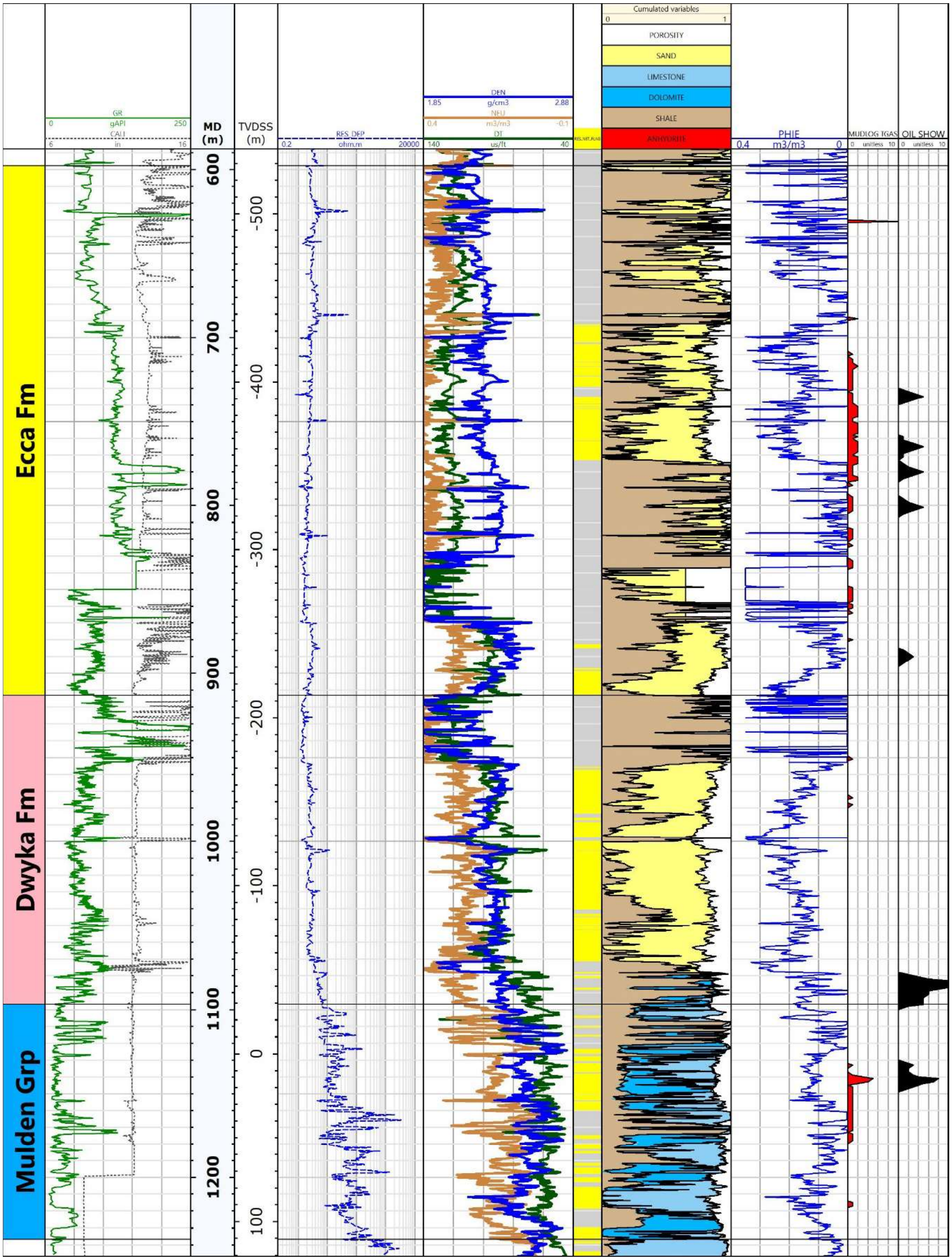
Figure 8

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

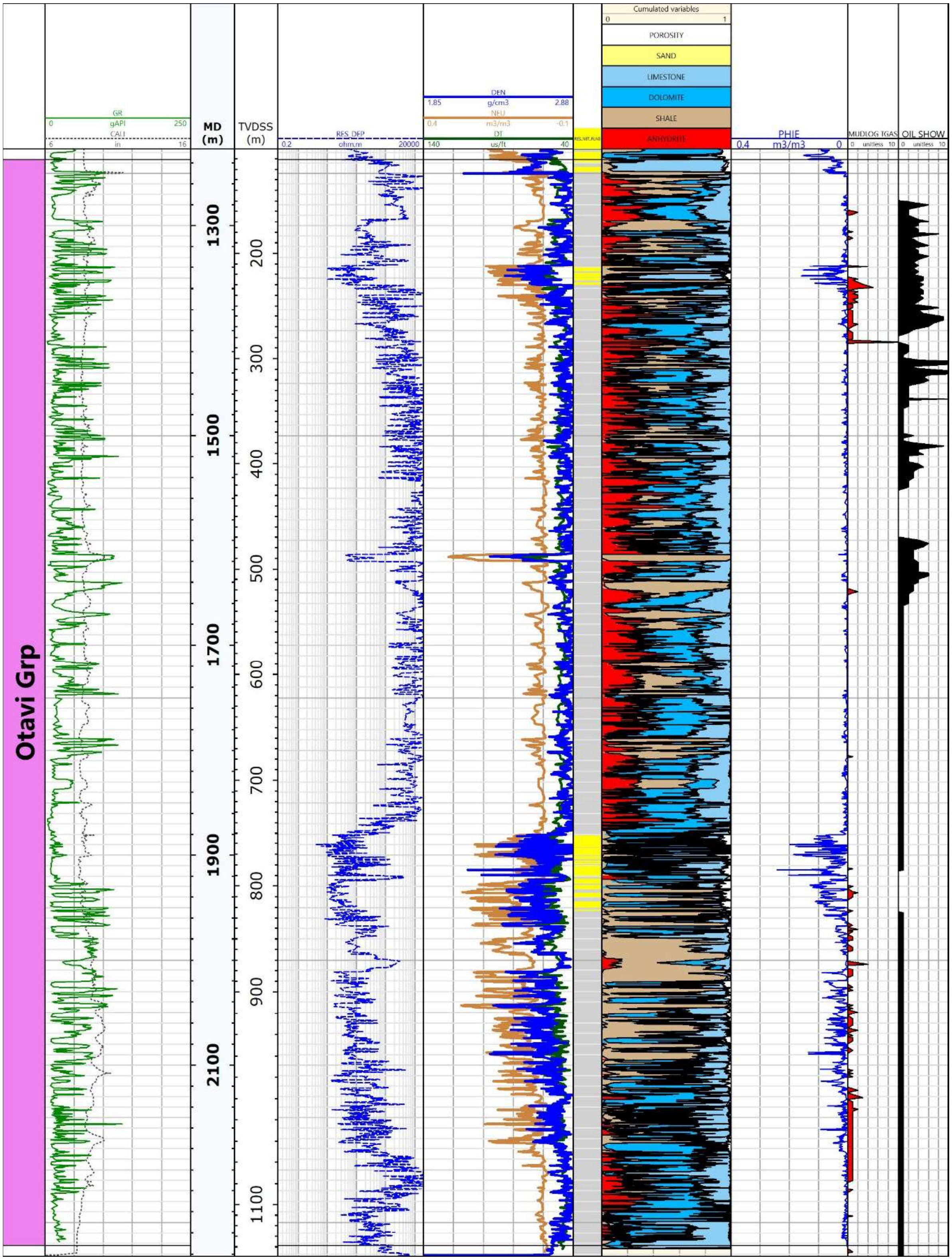
PROSPECT AND LEAD LOCATIONS
DAMARA FOLD AND THRUST BELT AREA
PEL 73, KAVANGO BASIN, NAMIBIA
RECONNAISSANCE ENERGY AFRICA LTD.
AS OF MARCH 31, 2023

Sub-Play	Location	Subclassification
A	F	Prospect
A	H	Prospect
A	B	Lead
A	C	Lead
A	D	Lead
A	E	Lead
B	I	Prospect
B	J-K	Prospect
B	L	Prospect
B	M	Prospect
B	O-P	Prospect
B	LL	Lead
B	MM	Lead
B	MMM	Lead
B	N	Lead
C	Q	Prospect
C	S	Prospect
C	R	Lead
C	RR	Lead
C	T	Lead
C	U	Lead

Kawe 6-2 Well Log
Ecca Formation to Mulden Group
Kavango Basin, Namibia



Kawe 6-2 Well Log
Otavi Group
Kavango Basin, Namibia



SUMMARY OF AREA PARAMETERS
PEL 73, KAVANGO BASIN, NAMIBIA
RECONNAISSANCE ENERGY AFRICA LTD.
AS OF MARCH 31, 2023

Sub-Play	Location	Target	Area (acres) P95	Area (acres) P50	Area (acres) P05
A	F	Upper Mulden	5,000	7,500	10,000
A	F	Lower Mulden	5,000	7,500	10,000
A	F	Otavi	4,000	6,000	8,000
A	H	North Upper Mulden	8,000	12,500	16,500
A	H	North Lower Mulden	8,000	12,500	16,500
A	H	North Otavi	6,500	9,500	13,000
A	H	South Upper Mulden	7,500	11,500	15,000
A	H	South Lower Mulden	7,500	11,500	15,000
A	H	South Otavi	3,500	5,000	7,000
B	I	Upper Mulden	11,500	17,250	23,000
B	I	Lower Mulden	11,500	17,250	23,000
B	I	Otavi	9,000	13,500	18,000
B	J-K	Upper Mulden	2,500	3,500	4,500
B	J-K	Lower Mulden	2,500	3,500	4,500
B	J-K	Otavi	1,500	2,000	2,500
B	L	Upper Mulden	7,000	10,500	14,000
B	L	Lower Mulden	7,000	10,500	14,000
B	L	Otavi	2,500	3,500	4,500
B	M	Upper Mulden	5,000	7,000	9,500
B	M	Lower Mulden	5,000	7,000	9,500
B	M	Otavi	3,500	5,250	7,000
B	O-P	Upper Mulden	11,000	16,000	21,500
B	O-P	Lower Mulden	11,000	16,000	21,500
B	O-P	Otavi	6,000	9,000	12,000
C	Q	Lower Mulden	4,500	6,500	8,500
C	Q	Otavi	2,500	4,000	5,000
C	S	Lower Mulden	4,500	6,500	8,500
C	S	Otavi	2,500	4,000	5,000

SUMMARY OF SELECTED RESERVOIR PARAMETERS BY SUB-PLAY
PEL 73, KAVANGO BASIN, NAMIBIA
RECONNAISSANCE ENERGY AFRICA LTD.
AS OF MARCH 31, 2023

		Geometric Factor (Decimal)			Net Thickness (m)			Porosity (Decimal)		
Sub-Play	Target	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
A	Upper Mulden	0.70	0.80	0.90	25	75	200	0.06	0.12	0.18
A	Lower Mulden	0.70	0.80	0.90	10	30	100	0.05	0.08	0.12
A	Otavi	0.70	0.80	0.90	25	50	150	0.05	0.08	0.12
B	Upper Mulden	0.50	0.65	0.80	10	25	50	0.06	0.12	0.18
B	Lower Mulden	0.50	0.65	0.80	10	50	150	0.05	0.08	0.12
B	Otavi	0.50	0.65	0.80	25	50	150	0.05	0.08	0.12
C	Lower Mulden	0.50	0.60	0.70	10	30	100	0.05	0.08	0.12
C	Otavi	0.50	0.60	0.70	25	50	150	0.05	0.08	0.12

		Gas Saturation (Decimal)			Formation Gas Volume Factor (scf/rcf)			Recovery Factor (Decimal)		
Sub-Play	Target	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
A	Upper Mulden	0.50	0.70	0.90	175	225	275	0.55	0.65	0.75
A	Lower Mulden	0.50	0.70	0.90	175	225	275	0.55	0.65	0.75
A	Otavi	0.50	0.70	0.90	200	250	300	0.55	0.65	0.75
B	Upper Mulden	0.50	0.70	0.90	175	225	275	0.55	0.65	0.75
B	Lower Mulden	0.50	0.70	0.90	175	225	275	0.55	0.65	0.75
B	Otavi	0.50	0.70	0.90	200	250	300	0.55	0.65	0.75
C	Lower Mulden	0.50	0.70	0.90	175	225	275	0.55	0.65	0.75
C	Otavi	0.50	0.70	0.90	200	250	300	0.55	0.65	0.75

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF BEST ESTIMATE UNDISCOVERED ORIGINAL GAS-IN-PLACE AND PROSPECTIVE GAS RESOURCES
PEL 73, KAVANGO BASIN, NAMIBIA
RECONNAISSANCE ENERGY AFRICA LTD.
AS OF MARCH 31, 2023

			Undiscovered OGIP (Bcf)		Unrisked Prospective Gas Resources (Bcf)			Risked Prospective Gas Resources P_g Only[1] (Bcf)			Risked Prospective Gas Resources P_g and P_d (Bcf)	
Sub-Play	Location	Target	Gross (100%)	Company Gross[2]	Gross (100%)	Company Gross[2]	P_g (Decimal)	Gross (100%)	Company Gross[2]	P_d (Decimal)	Gross (100%)	Company Gross[2]
A	F	Upper Mulden	1,467.2	1,320.5	953.7	858.3	0.100	95.4	85.8	0.580	55.3	49.8
A	F	Lower Mulden	473.5	426.2	307.8	277.0	0.100	30.8	27.7	0.580	17.8	16.1
A	F	Otavi	685.7	617.2	445.7	401.2	0.100	44.6	40.1	0.580	25.8	23.3
A	H	North Upper Mulden	2,419.4	2,177.5	1,572.6	1,415.4	0.100	157.3	141.5	0.580	91.2	82.1
A	H	North Lower Mulden	779.2	701.3	506.5	455.8	0.100	50.6	45.6	0.580	29.4	26.4
A	H	North Otavi	1,086.5	977.8	706.2	635.6	0.100	70.6	63.6	0.580	41.0	36.9
A	H	South Upper Mulden	2,234.8	2,011.4	1,452.7	1,307.4	0.083	120.6	108.5	0.580	69.9	62.9
A	H	South Lower Mulden	721.0	648.9	468.7	421.8	0.083	38.9	35.0	0.580	22.6	20.3
A	H	South Otavi	572.6	515.3	372.2	335.0	0.083	30.9	27.8	0.580	17.9	16.1
B	I	Upper Mulden	794.7	715.2	516.6	464.9	0.125	64.6	58.1	0.580	37.4	33.7
B	I	Lower Mulden	1,312.0	1,180.8	852.8	767.5	0.125	106.6	95.9	0.580	61.8	55.6
B	I	Otavi	1,238.6	1,114.7	805.1	724.6	0.125	100.6	90.6	0.580	58.4	52.5
B	J-K	Upper Mulden	558.0	502.2	362.7	326.4	0.071	25.8	23.2	0.525	13.5	12.2
B	J-K	Lower Mulden	178.3	160.5	115.9	104.3	0.071	8.2	7.4	0.525	4.3	3.9
B	J-K	Otavi	183.0	164.7	118.9	107.0	0.071	8.4	7.6	0.525	4.4	4.0
B	L	Upper Mulden	482.7	434.4	313.8	282.4	0.083	26.0	23.4	0.552	14.4	12.9
B	L	Lower Mulden	803.6	723.2	522.3	470.1	0.083	43.4	39.0	0.552	23.9	21.5
B	L	Otavi	324.4	292.0	210.9	189.8	0.083	17.5	15.8	0.552	9.7	8.7
B	M	Upper Mulden	1,123.5	1,011.1	730.3	657.2	0.111	81.1	73.0	0.552	44.8	40.3
B	M	Lower Mulden	363.6	327.2	236.3	212.7	0.111	26.2	23.6	0.552	14.5	13.0
B	M	Otavi	483.5	435.1	314.3	282.8	0.111	34.9	31.4	0.552	19.3	17.3
B	O-P	Upper Mulden	737.8	664.0	479.5	431.6	0.071	34.0	30.6	0.552	18.8	16.9
B	O-P	Lower Mulden	1,247.4	1,122.7	810.8	729.7	0.071	57.6	51.8	0.552	31.8	28.6
B	O-P	Otavi	831.3	748.2	540.4	486.3	0.071	38.4	34.5	0.552	21.2	19.1
C	Q	Lower Mulden	305.1	274.6	198.3	178.5	0.071	14.1	12.7	0.497	7.0	6.3
C	Q	Otavi	336.7	303.0	218.9	197.0	0.071	15.5	14.0	0.497	7.7	7.0
C	S	Lower Mulden	305.6	275.0	198.6	178.8	0.067	13.3	12.0	0.497	6.6	6.0
C	S	Otavi	333.2	299.9	216.6	194.9	0.067	14.5	13.1	0.497	7.2	6.5
Total			22,382.8	20,144.5	14,548.8	13,093.9		1,370.3	1,233.3		777.6	699.9

Totals may not add because of rounding.

Notes: In-place volumes are reported at surface conditions. Totals of in-place volumes and unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convienence only.

[1] Risked Prospective Gas Resources P_g Only do not include risking for Chance of Development (P_d) and only include risking for Chance of Geologic Success (P_g).

[2] Company Gross volumes are ReconAfrica's working interest share of the estimated gross (100%) volumes.

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