Investor Presentation

May 2024 Update

PetroTal Overview

Corporate Summary	USD Millions
Trading Price April 22, 2024	$0.63/share USD
Basic Shares (millions)	914
Market Cap	**$530**
Net surplus Q1 2024	$55
Enterprise Value Q1 2024	**$475**
EV/2024 Adjusted EBITDA(2)	2.4x
2024 Guidance bopd	16,500 – 17,500
Corp. Derivatives	0 mmbbls
ONP Derivatives $72/bbl average	2.4 mmbbls
Current Production (bopd)	18,208(1)

(1) Average of April 2024
(2) 2024 Adjusted EBITDA at $200 million using $77/bbl Brent. See footnotes and disclaimers for financial definitions.

Company Value Proposition

See footnotes for additional details and definitions

Company History

2018 — **958 bopd** (greenfield)

2019 — **4,131 bopd** (330% growth)

2020 — **5,675 bopd** (37% growth)

2021 — **8,956 bopd** (58% growth)

2022 — **12,200 bopd** (19% growth)

2023 — **14,248 bopd** (17% growth)

2024

2024 PRODUCTION GUIDANCE: 16,500-17,500 bopd (~20% production growth over 2023)

INVEST: approximately $150-$160 million of capital in 2024

PRODUCED: >18 million barrels (inception – Mar 2024)

CASH GENERATION: ~$200 million of adjusted EBITDA in 2024

COMMERCIALIZE: adding two additional route to markets in 2024 (Ecuador OCP and Yurimaguas)

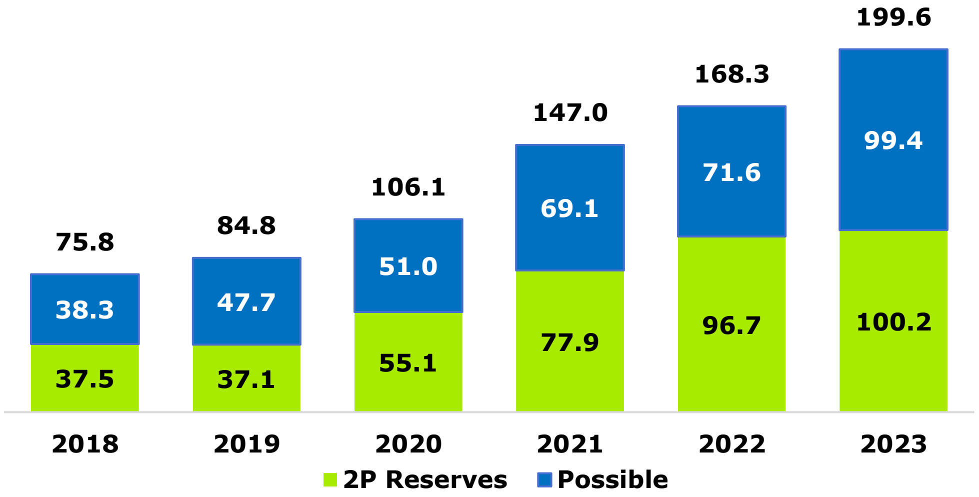
PRODUCTION CAPACITY: ~24,000 bopd

RETURN OF CAPITAL: returning an estimated $66 million of value through dividends and buybacks in 2024 with possibility of excess liquidity sweep amounts

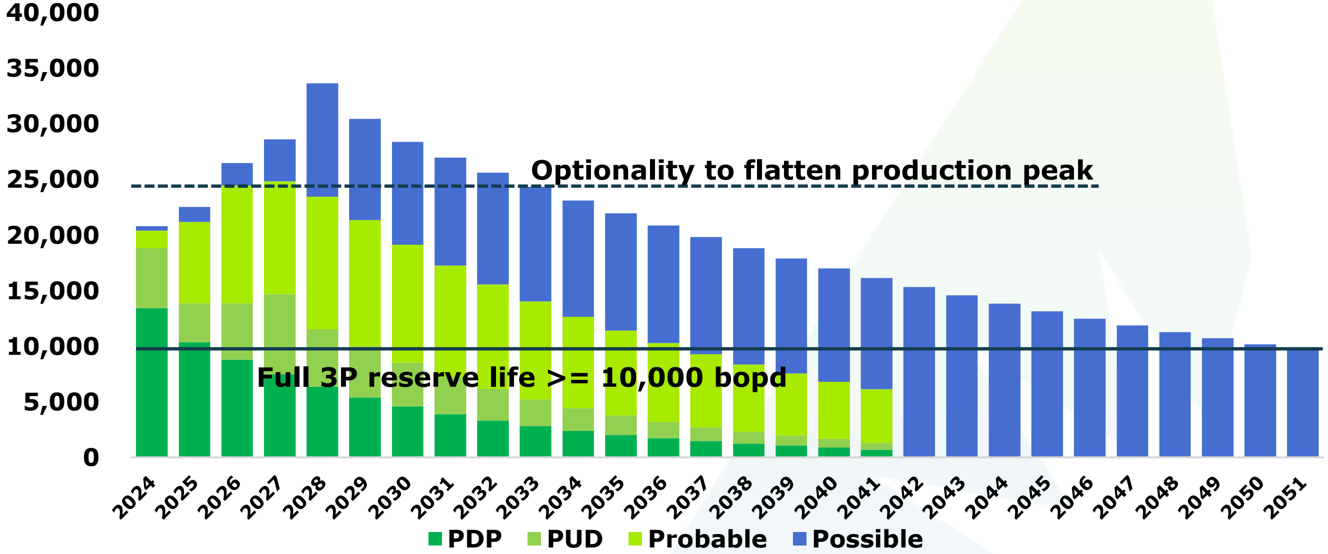
See footnotes for additional details and definitions

Bretaña 2023 YE Reserves Summary

Reserves Summary (mmbbl)



Netherland Sewell (NSAI) Production Profile (bopd)



Key Highlights

- 2P and 3P **recovery factors of 26% and 34%,** delivered in six years from zero production
- 2023YE **2P EUR now at 117 mmbbls**
- **Full reserve life > 10,000** bopd under 3P case
- Peak production **of 34,000 bopd** plausible
- Ability to flatten peak production into **multi year production profile** of 20,000 to 25,000 bopd
- **Billion dollar 2P** after tax valuation at $1.8/share

Key Reserve Metrics (USD millions)

Case	Wells	OOIP mmbbl	Reserves mmbbl	Recovery Factor	A-tax NPV (10) (USD/share)	F&D USD millions	F&D/bbl	Recycle Ratio ($45/bbl netback)
1P	23	326	48	19.7%	$888 ($1.0/share)	$125	$6.4	7x
2P	32	442	100	26.3%	$1,639 ($1.8/share)	$551	$7.7	6x
3P	36	595	200	34.3%	$2,508 ($2.8/share)	$768	$4.5	10x

Short-Term Strategy with Long-Term Results

Debt-free balance sheet

- **Debt free near top of the pricing cycle** to maximize free cash flow to **equity holders**
- **De-risk balance sheet** long term
- **Ability to access debt capital** if pricing cycle turns bearish

Execution of 2P and 3P development plans

- Drilling **2P and 3P** development locations **without unnecessary overcapitalization** of facilities and infrastructure
- Varied development pace that will generate a long-term production profile of > **10,000 bopd for 15+ years**

Returning free cash flow to shareholders

- Implemented a structured and **accretive share buyback program**
- **Established a quarterly dividend program paying US$0.015/share with a cash sweep enhancement** that can be maintained over the long term

Securing additional sales routes

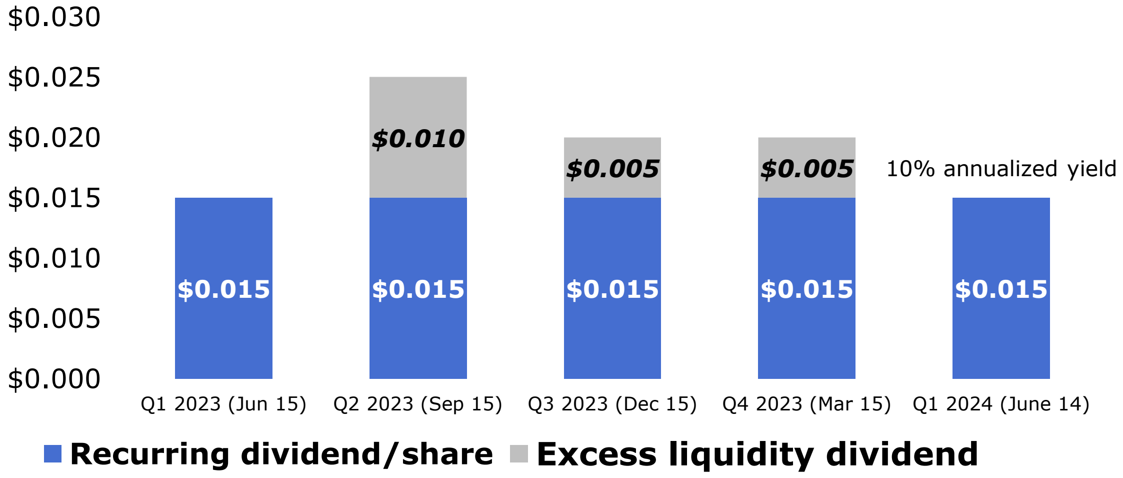
- Additional sales route, including the **reactivation of the ONP route**, will allow the Company to **avoid production constraints** in the dry season, **diversify credit risk**, and **unlock long term exploration** strategies for Blocks 95/107

Return of Capital Overview

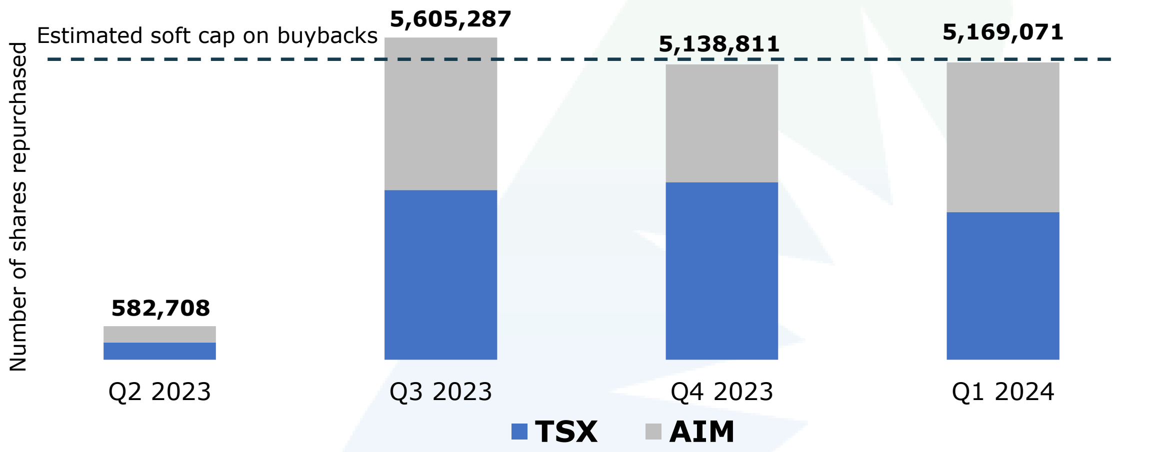
Total Dividends
$74 million returned *through Mar. 31, 2024*

Total Buybacks
$9.2 million returned *through Mar. 31, 2024*

Dividends Paid (USD/share)
Annualized yield based on $0.63/share USD



Share Buyback History
Buyback cap estimated using a $0.63/share USD



Dividend Policy

1. Pay a quarterly $0.015/share base dividend that is sustainable through low oil price environments
2. If economically viable on a forward-looking basis, increase the Company's base dividend by an amount equal to excess liquidity over $60 million
3. Liquidity is existing cash available at dividend approval date that may be adjusted by portions of unused credit capacity and or future capital/working capital needs

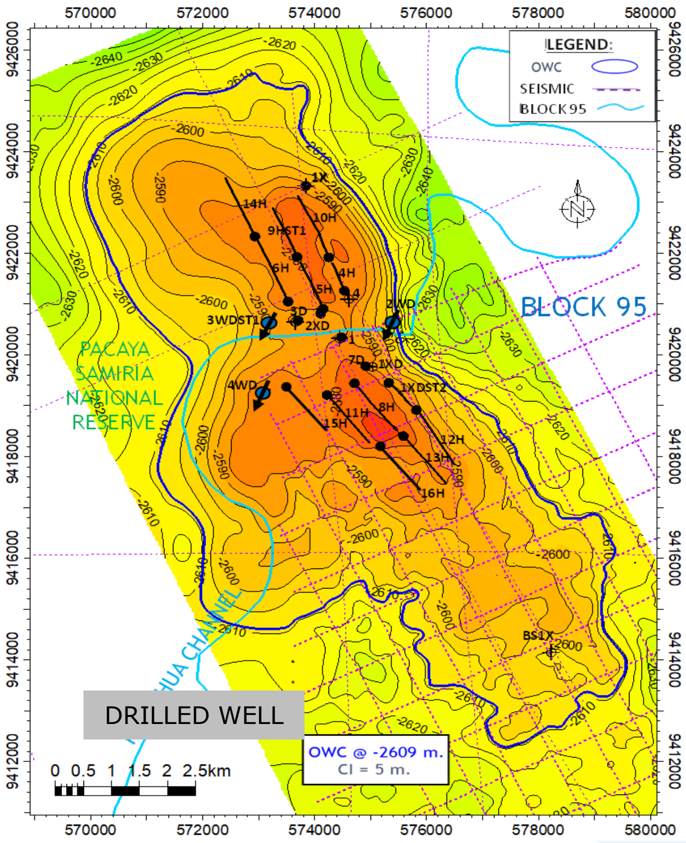
Buyback Policy

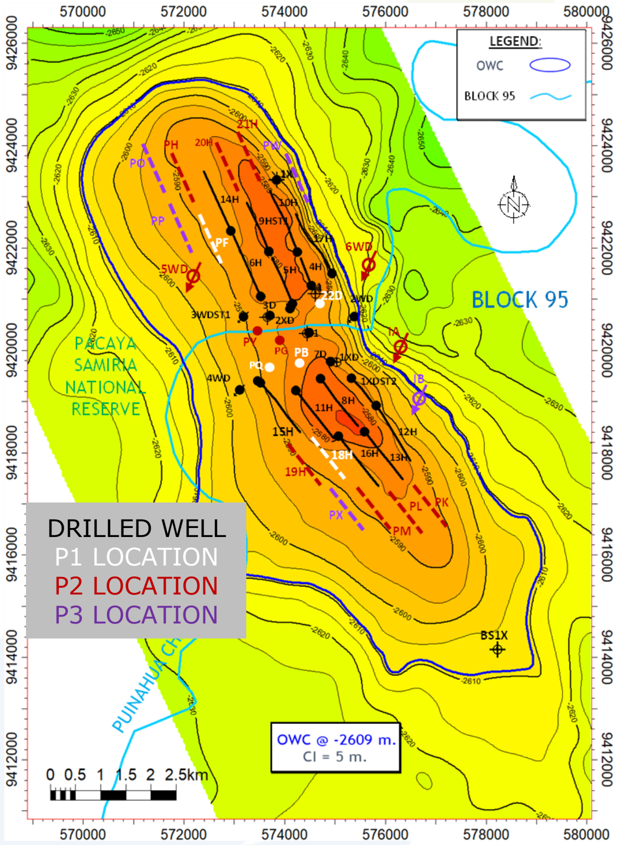
1. Buyback up to approximately 10% of the Company's public float subject to further volume and liquidity constrains set forth by the TSX and Company
2. Target up to approximately $3.0 million in buybacks per quarter totaling up to an estimated 4.5-5.5 million shares

Development Locations

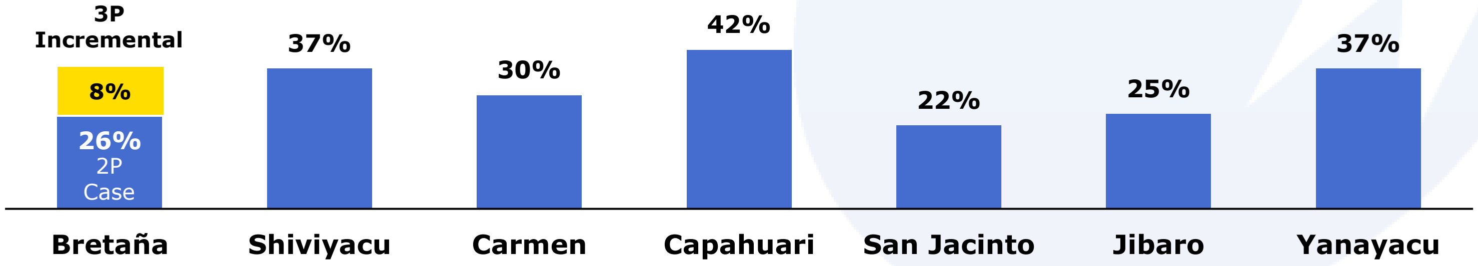
Technical Characteristics

- Well defined (6,000 city blocks)
- Vivian reservoir – Massive fluvial sands with excellent reservoir quality
  - Accountable for almost 70% of the oil production in the Marañón Basin in Peru
  - **Strong aquifer support** and water control using AICD technology assures pressure maintenance and high volumes of oil recovery
- Analogous fields in the basin **have recovery factors of 22-42% vs Bretaña at 26%** – possible Bretaña upside recovery factor of incremental 10-25%
- **18 drilled oil wells plus 5 PUD locations**
- **2P and 3P reserves case have 32 and 36 producing wells.** Potential exists for further infill drilling and "proving up" probable and possible drilling locations





Analogous Field Recovery Factors



Active and Potential Sales Routes

Total Potential Sales Capacity = 70,000 bopd

PetroTal will have commercialized additional sales routes prior to drilling its first exploration well in Block 95 assuming favorable seismic results

Available	In progress

	To	Status	Capacity	Timeline	Expandable
1	Station 1 direct	Petroperu credit N/A	25,000 bopd	N/A	TBD
2	Iquitos	Active	Up to 5,000 bopd	N/A	With blending
3	Manaus (Brazil)	Active	Up to 20,000 bopd	N/A	With dedicated storage
4	OCP (Ecuador)	Active pilot	5,000 bopd	2024 (pilot)	With additional barges
5	Station 5 direct	In progress	5,000 bopd	2024/2025	With facility investment
6	Yurimaguas	In progress	5,000 bopd	2024/2025	TBD
7	Lima via truck/barges	In progress	5,000 bopd	2024/2025	BioIFO opportunity

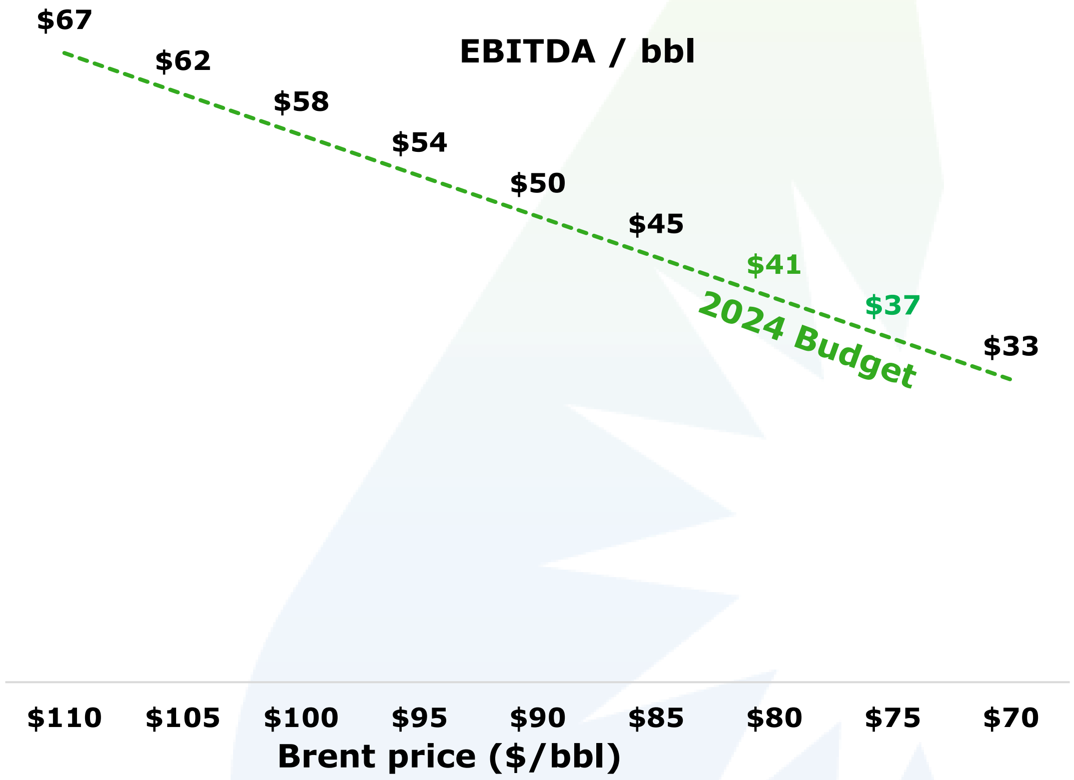
See footnotes for additional details and definitions

Netback Contribution by Sales Route

Run Rate Netback by Sales Route at 17,000 bopd ($/bbl)

Netback Summary $/bbl	Brazil	Iquitos	OCP / Yurimaguas (pilots)	Total	ONP (run rate)	OCP (run rate)	Yurimaguas (run rate)
Sales (bopd)	14,000	1,600	1,400	17,000	~20,000	~5,000	~5,000
Brent (@~$77/bbl)	**$77.0**	**$80.0**	**$77.0**	**$77.0**	**$74.0**	**$77.0**	**$77.0**
Differential *(estimated)*	($6.0)	($13.0)	($7.0)	($6.1)	($4.0)	($7.0)	($4.0)
Transportation *(estimated)*	($16.0)	-	-	($12.8)	($11.0)	-	-
Royalties and social trust	($5.5)	($6.0)	($5.5)	($5.8)	($5.0)	($5.5)	($5.5)
Net Revenue	**$49.5**	**$61.0**	**$64.5**	**$52.3**	**$54.0**	**$64.5**	**$67.5**
Lifting	($6.0)	($6.0)	($6.0)	($6.0)	($6.0)	($6.0)	($6.0)
Supervision & monitoring	-	($1.0)	($2.0)	($0.5)	($0.5)	($0.5)	($0.5)
Barging service inc. labor	-	($3.0)	($10.0)	($1.3)	($4.0)	($12.0)	($8.0)
Barging diesel	-	($1.0)	($2.0)	($0.2)	($1.0)	($1.0)	($1.0)
Pipeline & oil transfers	-	-	($5.0)	($0.9)	-	($3.0)	($2.0)
Trucking	-	-	($11.0)	($1.3)	-	-	($15.0)
Netback	**$43.5**	**$50.0**	**$28.5**	**$42.1**	**$42.5**	**$42.0**	**$35.0**
Cash portion of G&A	($4.1)	($4.1)	($4.1)	($4.1)	($4.1)	($4.1)	($4.1)
Normalized EBITDA	**$39.4**	**$45.9**	**$24.4**	**$38.0**	**$38.4**	**$37.9**	**$30.9**

Normalized EBITDA/bbl sensitivity at 17,000 bopd ($/bbl)



Key Highlights

- **Diluent not required for Brazilian route**
- Table excludes erosion and community opex costs that are nonrecurring
- **>50% normalized EBITDA margins** at $80/bbl Brent
- **~80% of every dollar increase in Brent** falling to netback
- OCP and Yurimaguas estimated transportation includes oil transfer terminal fees, marketing fees, and secondary pipeline fees
- ONP, OCP and Yurimaguas run rate estimates are with commercial recurring volumes inclusive of opex scaling and cost synergies

Long-Term Strategy

Achieve $2 billion in market capitalization via expansion

- Source **accretive M&A** opportunities in North and South America
- Source **inorganic block growth opportunities** in Peru
- Proceed with exploration development plans in **Blocks 95 and 107**

Achieve Bretaña production plateau

- **Drilling 3-4 wells per year** with little to no social related downtime
- Post-production plateau, maintain a production level that **optimizes infrastructure**
- Be the gold standard in Peru for **operational excellence as Peru's largest oil producer**
- Leverage our **diversified and commercially simple transportation strategy** allowing for cost savings over the long run

Materially meet or exceed ESG targets in Bretaña

- Realization and **completion of material carbon offset projects**
- **Biodiversity** related projects for preservation of the National Reserve Pacaya Samiria
- Management and funding of PetroTal's social trust with **economic development focus** in Puinahua

Return free cash flow to shareholders

- **Significant return of capital to shareholders via dividends and/or buybacks**

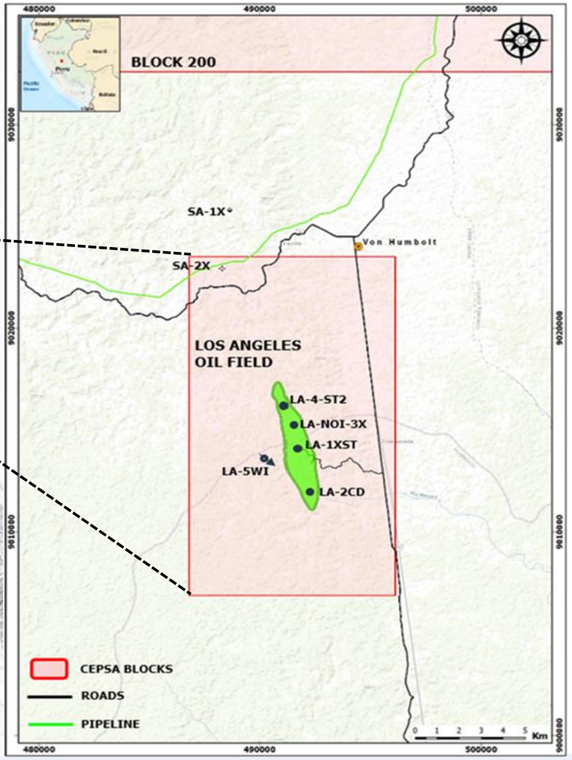
Optimize cost structure and operating synergies

- Make continued investments in field infrastructure projects that **lower operating costs** in an environmentally friendly way (diluent, power, and fuel focused)
- Target **20% to 30% OPEX reductions** post-production plateau in Bretaña via technology scaling

Low Cost, Strategic Acquisition Of Block 131

Location Overview

~1,400 Acre Field

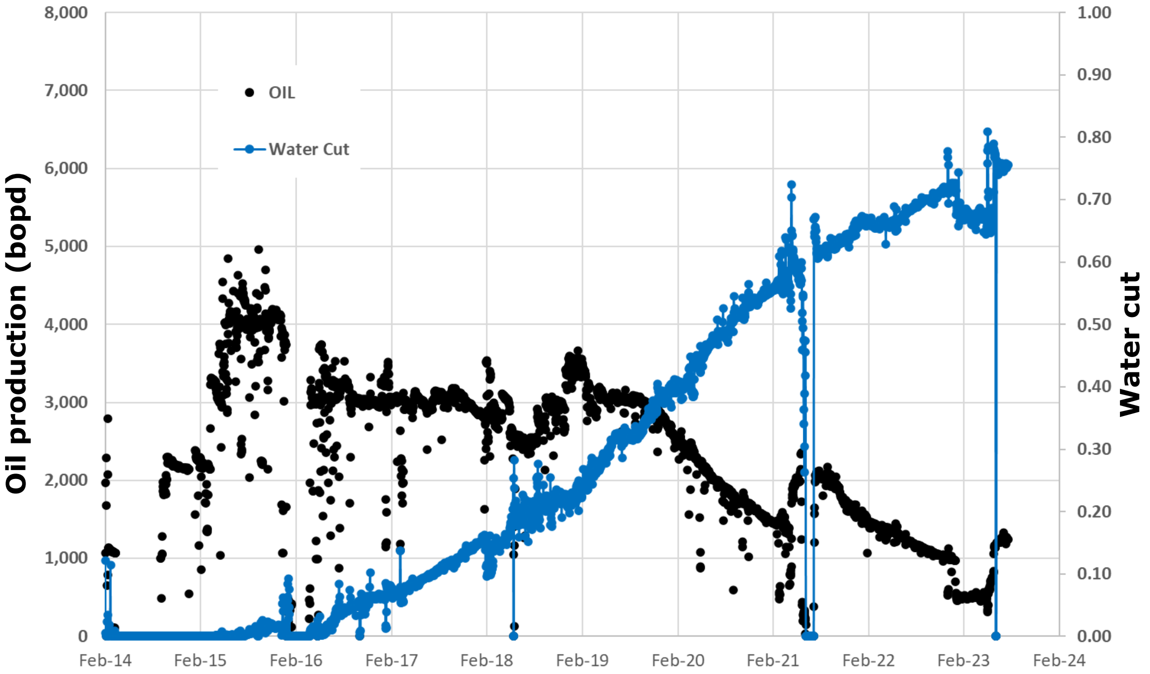


Overview

- Acquisition of Cepsa Peru (announced on May 8, 2024) includes **100% working interest** in **Block 131** which holds the light oil producing Los Angeles Field in the Ucayali Basin (discovered in 2013)
- Consideration of **$5.0 million** before working capital and closing adjustments with **effective date of January 1, 2024**
  - **Closing is subject to regulatory approvals**
- Four producing wells, producing 900 bopd of 40-45 API oil from the Cretaceous Cushabatay sand (includes one water injector)
- 3 wells booked with nearly 5.0 million barrels of 2P reserves and additional unbooked identified drilling locations
- Modern infrastructure in place to accommodate up to 5,500 bopd (>5x current production)

Block 131 Production History & Reserves Summary

Historical Production



Reserves & EUR Summary/Estimates (MMBO)

Cuml. Prod	Category	Reserves	EUR	RF%
7.6	PDP	+0.96	8.6	29%
	1P	+3.07	10.7	36%
	2P	+4.88	12.5	42%

Key Highlights

- Low risk, well understood conventional light oil reservoir in the Cushabatay sand
- Four-way closure primarily composed of fluvial channels of relatively uniform thickness, good porosity / permeability and clear OWC
- Cumulative production about 7.6 MMbo; Estimated OOIP of 30 MMbo
- Strong water drive, good mobility ratio and reservoir depth 1,550 mTVD
- Current recovery factor of 25% is low based on analog experience
- Minimal to no infrastructure investments needed

Low Risk Upside Opportunities

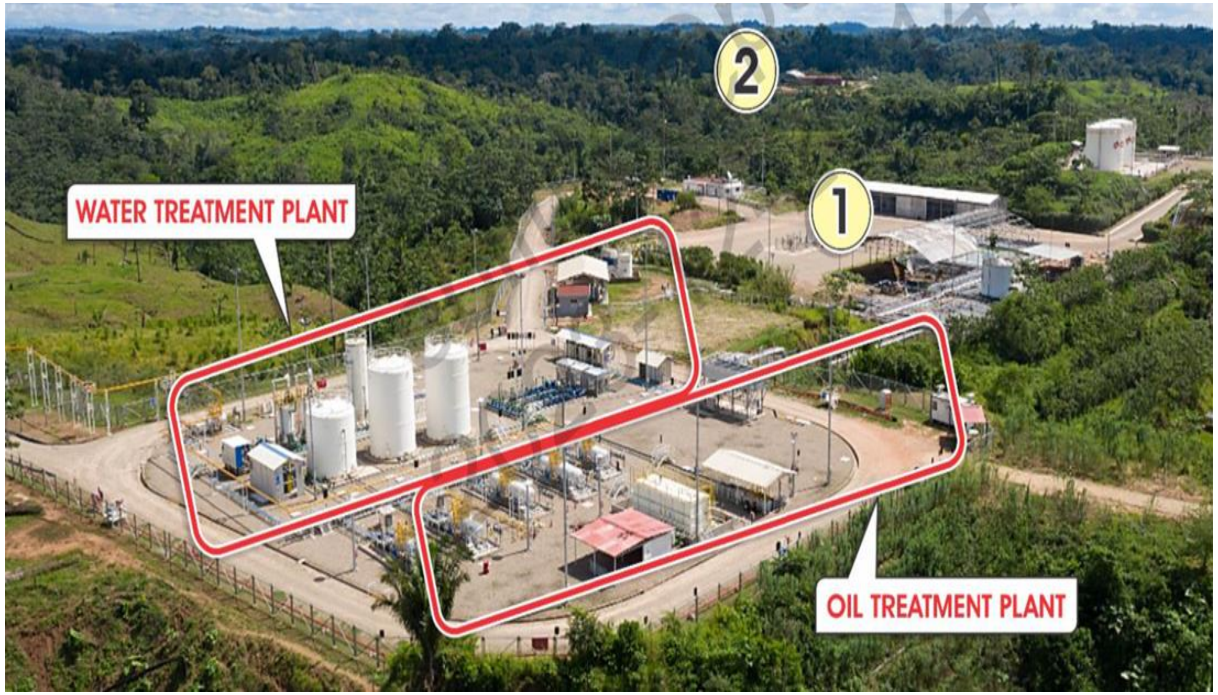
- Bypassed oil provides for horizontal well locations high on structure
- Use hydraulic pumps (vs ESPs) and optimize tubing to reduce Opex
- Better voidage replacement should help reduce Opex with less chemical treatments
- Blending synergies at the Iquitos refinery driving increased sales capacity for Bretana oil and improved differentials

Block 131 Strategic Rationale

- Production with offtake optionality not subject to dry season weather
- Crude transportation synergies with Bretaña that unlock increased sales to Iquitos
- Crude sales synergies with Bretaña that potentially lower overall differentials and increase the Iquitos netback
- Strong acquisition metrics and low cost entry into complimentary and strategic basin
- Operationally straight forward development plan with 3 or 4 low risk initiatives to optimize production profiles and OPEX
- Production upside in lower zones (Copacabana) and via identified infill drilling locations

Block 131 Infrastructure In Place

Oil production capacity of 5,500 bopd



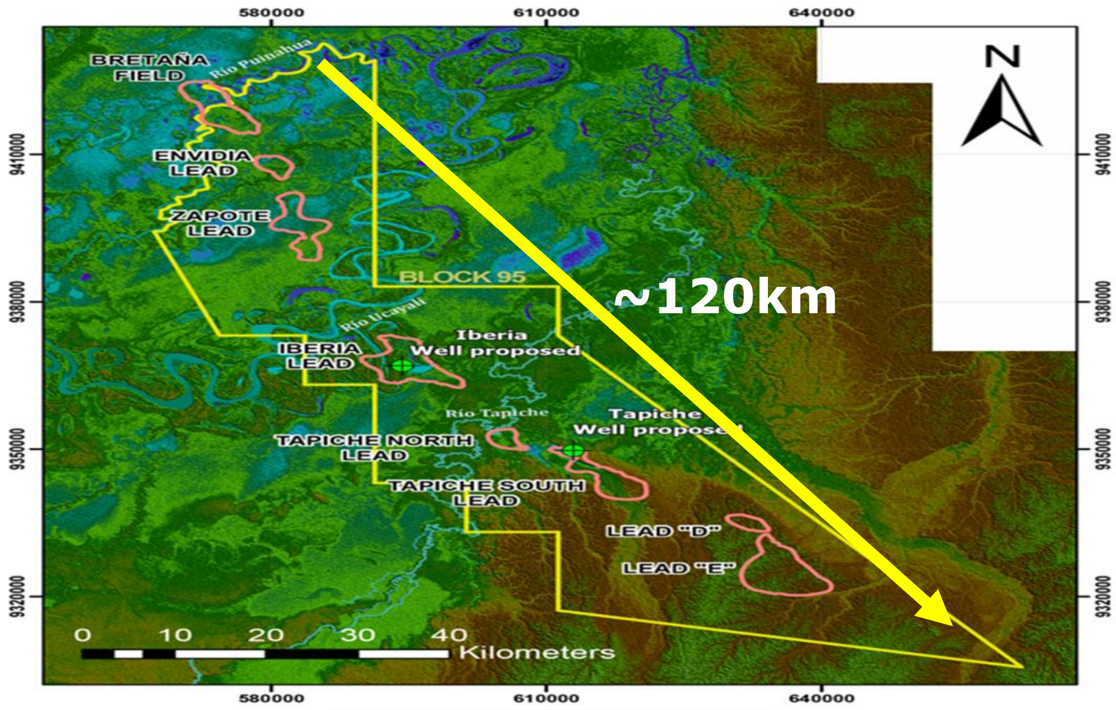
Water treatment

Key highlights

- Facilities in excellent condition with no near-term capital needed
- Can handle approximately 5,500 bopd and 11,000 bwpd

Block 95 Expansion Risked Spending Profile and Timeline

Drilling Schedule ($ millions)	Capex per well	Q1 24	Q2 24	Q3 24	Q4 24	Q1 25	Q2 25	Q3 25	Q4 25	Q1 26	Q2 26	Q3 26	Q4 26	Q1 27	Q2 27	Q3 27	Q4 27	Q1 28	Q2 28	Q3 28	Q4 28	Q1 29	Q2 29	Q3 29	Q4 29	Q1 30	Q2 30	Q3 30	Q4 30	Q1 31	Q2 31	Q3 31	Q4 31
Iberia	$20/well											x	x	x		x		x		x		x		x				+2 additional wells					
Tapiche Sou.	$20/well															x	x	x		x		x		x		x		x		x		x	
Lead E	$20/well																			x	x	x	x	x	x	+24 additional wells							
Zapote	$20/well																							x	x	x		x		x		x	
Discovery well / Water disposal	Seismic / Permits/ interpretation			$30 million								First production Commercial viability																+1 additional well					

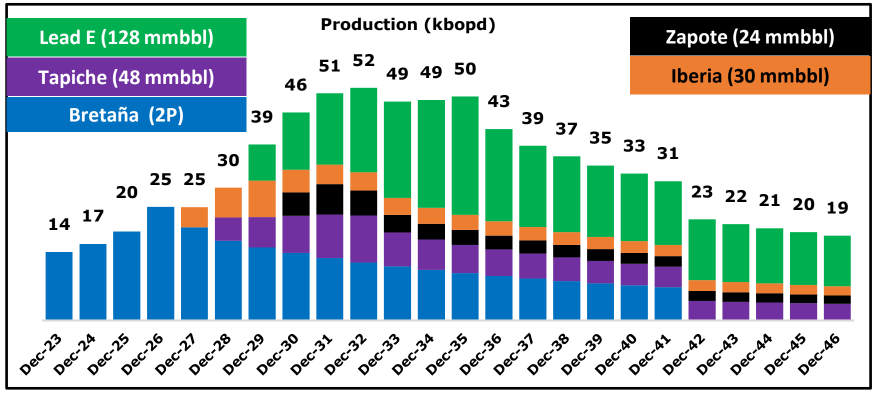


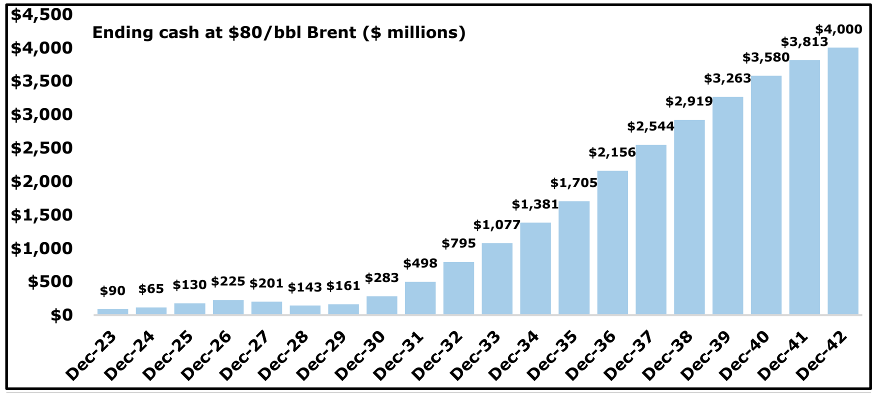
Block 95 Capex estimates (2024–2026)

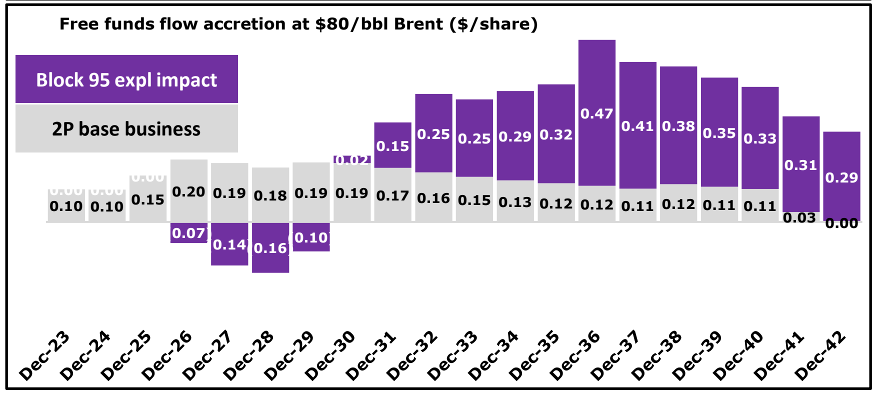
- **Risked dry hole Capex = ~$50-$70 million from 2024 – 2026**
  - ~$12 million in 2024 (seismic)
  - ~$18 million in 2025 (seismic)
  - ~$25-$30 million in 2026 (drilling)

- **If deemed commercial → ~$10/bbl F&D for long term commerciality**

Profiling Bretaña and Block 95 Expansion (100% WI View @ $80/bbl Brent)







Summary		5 YR	$/bbl	10 YR	$/bbl	15 YR	$/bbl	30 YR	$/bbl
Oil produced	mmbbl	**39**		**119**		**203**		**327 (230 new)**	
Well count		31		66		78		78	
Avg production	**bopd**	21,070		32,572		37,057		29,832	
EBITDA	**millions**	**$1,631**	**$42**	**$4,997**	**$42**	**$8,628**	**$43**	**$14,230**	**$44**
Tax	"	($388)	($10)	($1,133)	($10)	($1,958)	($10)	($3,642)	($11)
Other	"	$30	$1	$30	$0	$30	$0	$30	$0
Funds flow	"	**$1,273**	**$32**	**$3,895**	**$33**	**$6,701**	**$33**	**$10,619**	**$32**
Capex	"	($798)	($20)	($2,485)	($21)	($3,203)	($16)	($3,263)	($10)
Change in debt	"	($80)	($2)	($80)	($1)	($80)	($0)	($80)	($0)
Change in equity	"	$8	$0	$8	$0	$8	$0	$8	$0
Dividends	"	($264)	($7)	($544)	($5)	($824)	($4)	($1,104)	($3)
Buybacks	"	($58)	($1)	($118)	($1)	($178)	($1)	($238)	($1)
Change in cash	"	$81		$675		$2,424		$5,942	
Ending cash	"	**$201**		**$795**		**$2,544**		**$6,062**	
Free funds flow	"	**$395**	**$10**	**$1,329**	**$11**	**$3,418**	**$17**	**$7,276**	**$22**

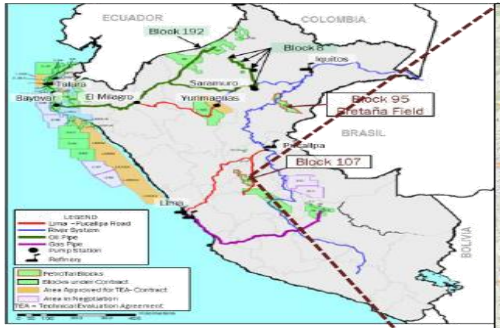
Key highlights

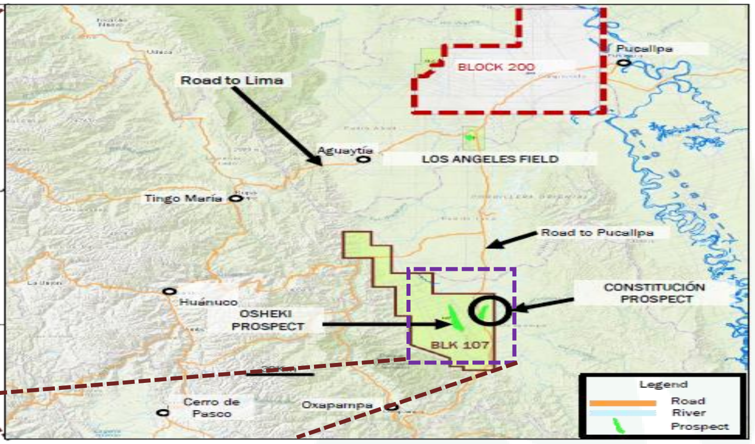
- **Minimum cash levels acceptable under an $80/bbl Brent scenario (long term price deck)**
- **Total ending cash in 2030 of ~$280 million (after dividend and buyback program)**
- **After tax free funds flow accretion neutral in mid 2033**
- **AT IRR > 40%**

See footnotes for additional details and definitions

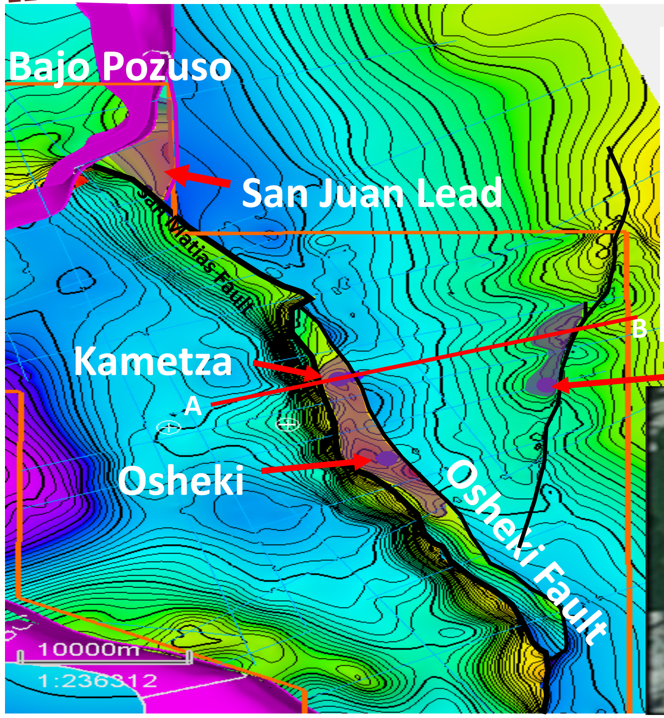
Osheki-Kametza Technical Overview (Block 107)

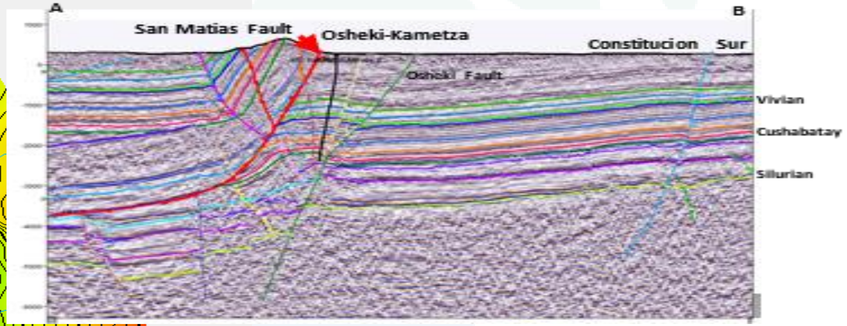
Unrisked prospects	Best estimate (mmbbl)	Mean (mmbbl)	Pg (%)
Osheki-Kametza	278.4	534.2	21 - 28
Constitución Sur	31.6	68.5	18 - 21
Unrisked leads	**Best estimate (mmbbl)**	**Mean (mmbbl)**	
Bajo Pozuzo	259.0	1,016.5	
Lead A	20.1	39.0	
San Juan	72.9	147.4	
Total	**662.0**	**1,805.6**	

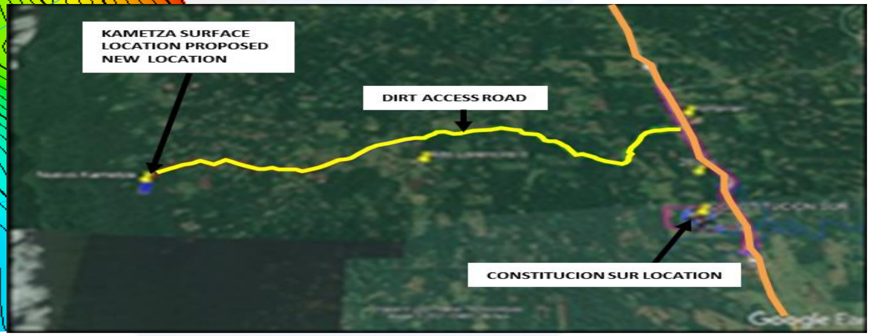




Depth Structural Map Cushabatay

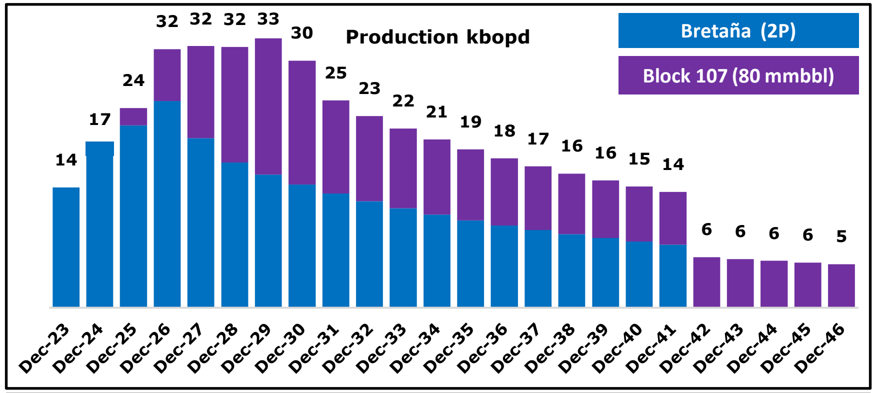


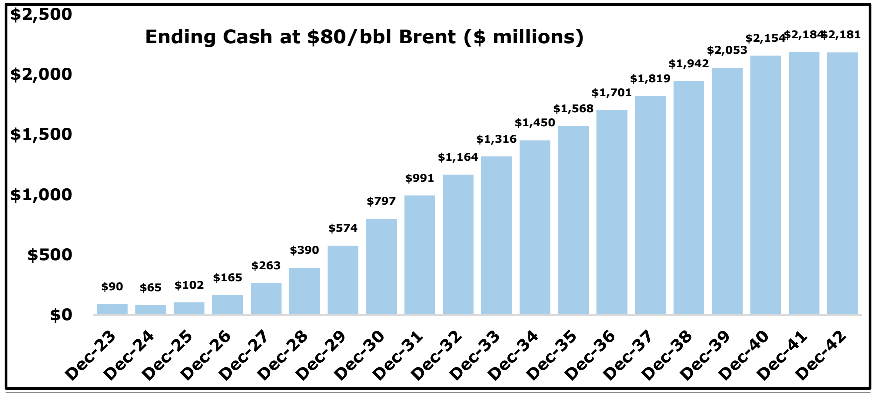


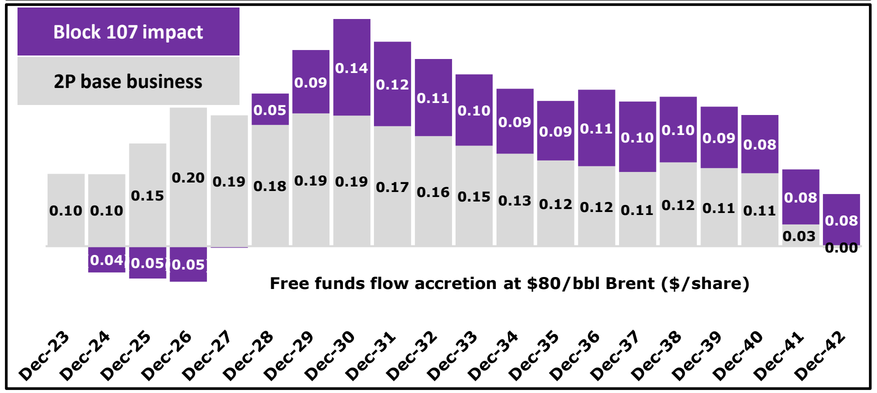


- 100% owned and operated block with > 252,000 hectares (> 622,000 acres), located in the Ucayali basin
- 3D geologic model supports Cretaceous reservoirs with oil charge from high quality Permian source rocks
- Two drillable prospects identified on 2-D seismic
  - Osheki-Kametza prospect
  - Constitución Sur prospect
- Recent reinterpretation of the seismic has shown that the Osheki prospect has two main structural culminations. To the south Osheki and to the north Kametza with a more accessible surface location.
- Due to smoother topography and dirt road access from main road to the Kametza surface location, the Osheki-Kametza prospect can now be drilled at an estimated cost of $28 million rather than the $40 million required to drill the Osheki surface location. Drilling costs for Constitución Sur are $22 million **(NPV neutral with tax benefits utilized by Block 95 if dry hole)**
- Exploration commitment to drill two exploration wells extended to 2025/2026
- **PetroTal will seek a farmout partner** for the commitment wells or for longer term development after drilling the first well. Gran Tierra Energy has a 20% back-in interest in the block

Profiling 2P Bretaña and Block 107 (100% WI View @$80/bbl Brent)







Summary		**5 YR**	**$/bbl**	**10 YR**	**$/bbl**	**15 YR**	**$/bbl**	**30 YR**	**$/bbl**
Oil produced	mmbbl	**45**		**97**		**133**		**176** (80 Block 107)	
Well count		42		56		56		56	
Avg production	**Bopd**	24,136		26,645		24,246		16,063	
EBITDA	**millions**	**$1,856**	**$41**	**$4,191**	**$43**	**$5,824**	**$44**	**$7,788**	**$44**
Tax	"	($446)	($10)	($1,029)	($11)	($1,482)	($11)	($2,150)	($12)
Other	"	$30	$1	$30	$0	$30	$0	$30	$0
Funds flow	"	**$1,440**	**$32**	**$3,192**	**$33**	**$4,372**	**$33**	**$5,668**	**$32**
Capex	"	($904)	($20)	($1,414)	($14)	($1,600)	($12)	($1,660)	($9)
Change in debt	"	($80)	($2)	($80)	($1)	($80)	($1)	($80)	($0)
Change in equity	"	$8	$0	$8	$0	$8	$0	$8	$0
Dividends	"	($264)	($6)	($544)	($6)	($824)	($6)	($1,104)	($6)
Buybacks	"	($58)	($1)	($118)	($1)	($178)	($1)	($238)	($1)
Change in cash	"	$143		$1,044		$1,699		$2,595	
Ending cash	"	**$263**		**$1,164**		**$1,819**		**$2,714**	
Free funds flow	"	**$457**	**$10**	**$1,698**	**$17**	**$2,693**	**$20**	**$3,929**	**$22**

Key highlights

- **Minimum cash levels acceptable under an $80/bbl Brent scenario (long term price deck)**
- **Total ending cash in 2030 of ~$1.2 million (after dividend and buyback program)**
- **After tax free funds flow accretion neutral in mid 2029**
- **AT IRR > 35%**

ESG Leadership

PetroTal's Four Pillars of Sustainability

Carbon Emissions

Carbon Footprint

- 6.96 kg/bbl scope 1/2 emissions in 2022 (11.4kg in 2021)

Oil Sales (mmbbls)
2020 – 2.1 | 2021 – 3.3 | 2022 – 4.5

Gross Emissions (CO2eq)
2020 – 22,460 | 2021 – 37,290 | 2022 – 30,984

Energy Consumption (TJ)
2020 – 274 | 2021 – 404 | 2022 – 357

2022 Energy Milestones

- Carbon footprint certification in 2022 in Peru
- Approval of feasibility studies for energy transition
- Recognized GHG reduction from Autonomous Inflow Control Devices ("AICD")

3 Year Emissions Plan

- Carbon assessment of equipment
- Development of heat recovery system
- Elimination of gas flaring

7 Year Emissions Plan

- Establish a carbon credit program via carbon sequestration in peat bogs within the Pacaya Samiria National Reserve
- Installation of geothermal energy facility using near 100C water produced at field

See the latest ESG Sustainability report at www.petrotalcorp.com

Appendix

Senior Management Team

Manolo Zúñiga, *Director, President & Chief Executive Officer*

- Native Peruvian with >30 years of experience in petroleum engineering
- Started career with Occidental Petroleum Corp (“Occidental”) in Bakersfield & Block 192 in Peru
- Founder and former CEO of BPZ Energy
- Helped shape policies promoting oil investments in Peru, including the current long-term test regulation

Camilo McAllister, *Executive Vice President & Chief Financial Officer*

- Previously Executive Vice President, Finance and Chief Financial Officer of Constellation and Frontera Energy
- MBA from The Fuqua School of Business at Duke University
- Over 30 years of leadership experience in international energy

Jose Contreras, *Senior Vice President Operations*

- Over 25 years experience managing complex oil production and technical operations
- Various executive roles ranging from guiding international safety, security, and sustainability performance for projects and drilling; ensuring safe and efficient upstream and midstream onshore operations
- Mr. Contreras holds a Bachelor of Science in Chemical Engineering from the Universidad Central de Venezuela and a Master of Science in Petroleum Engineering and Project Development from the Institut Français du Pétrole

Glen Priestley, *Vice President Finance*

- Over 30 years experience leading finance, capital markets, treasury and planning functions for upstream and midstream energy Companies
- Previously VP finance and Treasurer at Energy21
- Holds an executive MBA from Texas A&M

Emilio Acin Daneri, *Vice President, Business Development*

- Over 30 years experience in negotiating and managing upstream business development, new ventures and commercial agreements for international E&P Companies
- Extensive experience in originating and executing M&A transactions in Latin America and abroad
- Held several commercial and finance roles at various large E&P companies including past president and treasurer of Argentina Oil and Gas in Houston. Mr. Acin Daneri holds a Bachelor Accounting degree from the University of Buenos Aires

Guillermo Florez, *General Manager Peru*

- Over 15 years of experience in energy holding variance operational and executive management positions at BPZ Energy, Frontera Energy and Total Energy
- In depth knowledge and experience in project management, business development and planning
- Holds an MBA from Robert Gordan University specializing in Oil and Gas management and leadership and sustainability studies from MIT Sloan School of Management

Board of Directors

Highly-Experienced Governance

Mark McComiskey, *Non-Executive Director and Chairman*
- Partner of Avaio capital with a focus on energy and digital infrastructure
- Founding Partner of Vanwall Capital and Managing Partner of Prostar Capital
- Former Principal of Clayton, Dubilier & Rice, Inc. and an associate at the law firm of Debevoise & Plimpton, LLP

Roger Tucker, *Non-Executive Director*
- CEO of Africa Oil
- Over 30 years working as a senior executive in the Energy Sector
- Work history in multinational major oil and gas companies, independent E&Ps and private equity investing

Eleanor Barker, *Non-Executive Director*
- President of Barker Oil Strategies since 2017
- Formerly worked in industry for Esso and Gulf Canada
- Former Oil and Gas Investment Analyst for over 30 years

Gavin Wilson, *Non-Executive Director*
- Investment Manager for Meridian
- Former founder & manager of RAB Energy & RAB Octane listed investment funds

Jon Harris, *Non-Executive Director*
- CEO of Gulf Keystone Petroleum
- Over 30 years senior leadership experience in international E&P Companies
- Masters of Engineering in Fuel and Energy from the University of Leeds, UK

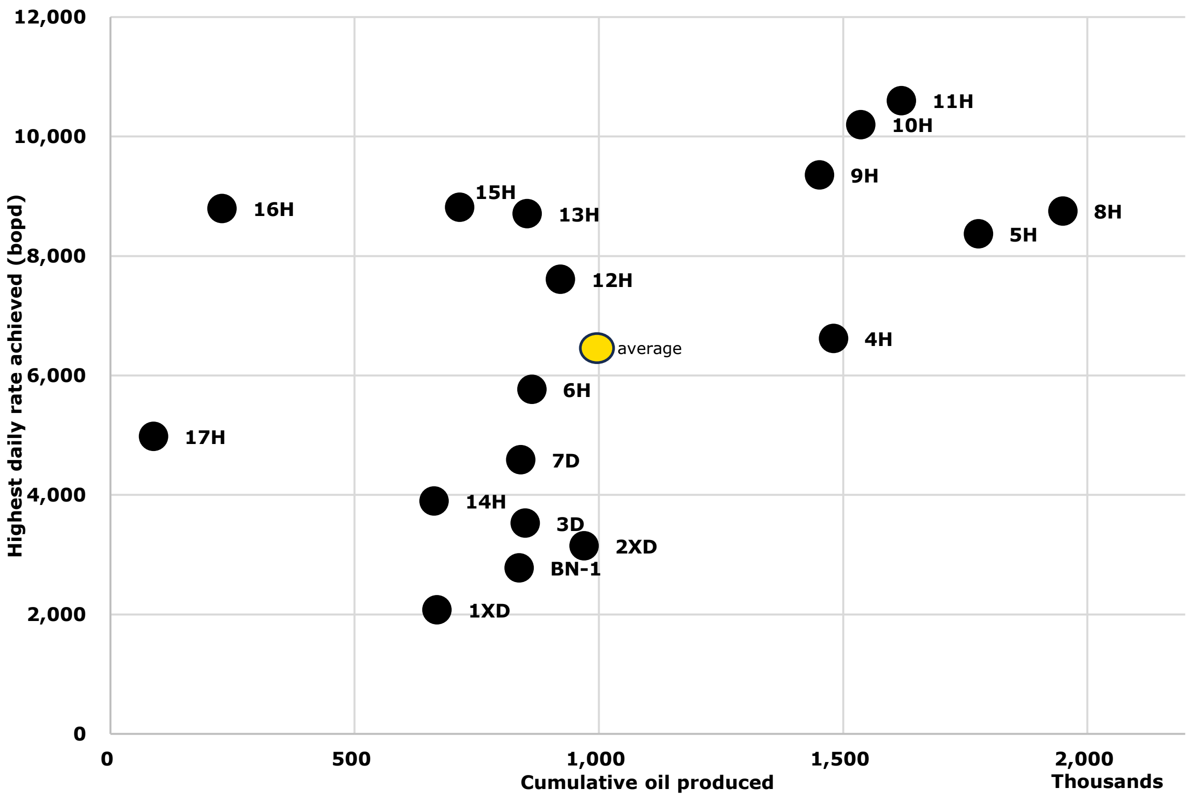
Felipe Arbelaez Hoyos, *Non-Executive Director*
- Current Senior VP Hydrogen and CCS for BP
- Over 20 years of senior commercial and ESG experience in international oil and gas
- Masters of Mechanical Engineering and Finance

Emily Morris, *Non-Executive Director*
- Private corporate financial consultant in energy
- Over 20 years of investment banking experience in London
- Includes research, fund management, sales, and M&A advisory across resource sectors

Manolo Zúñiga, *Director, President and CEO*
- See bio on previous slide

Operational Track Record

Max oil rate vs cumulative oil (inception until Mar 31, 2024)



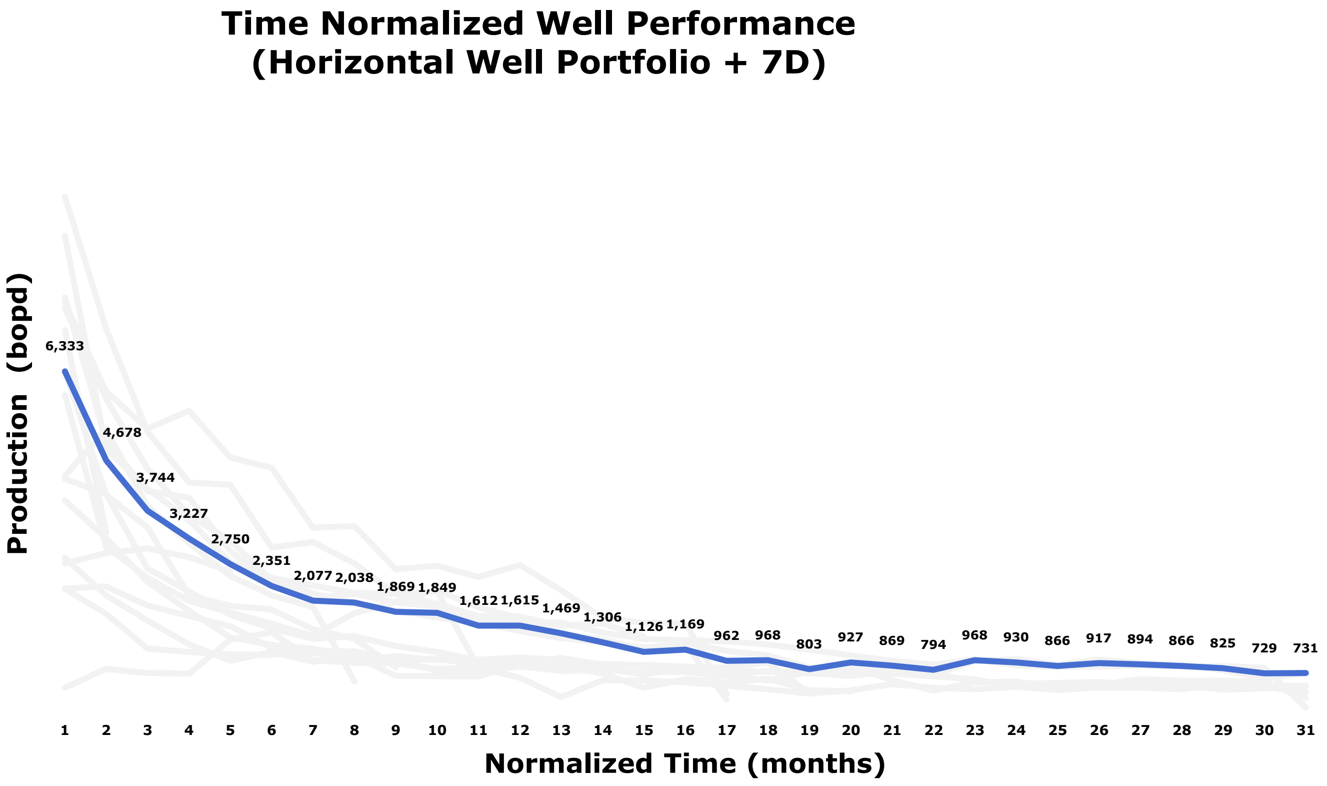
Key highlights

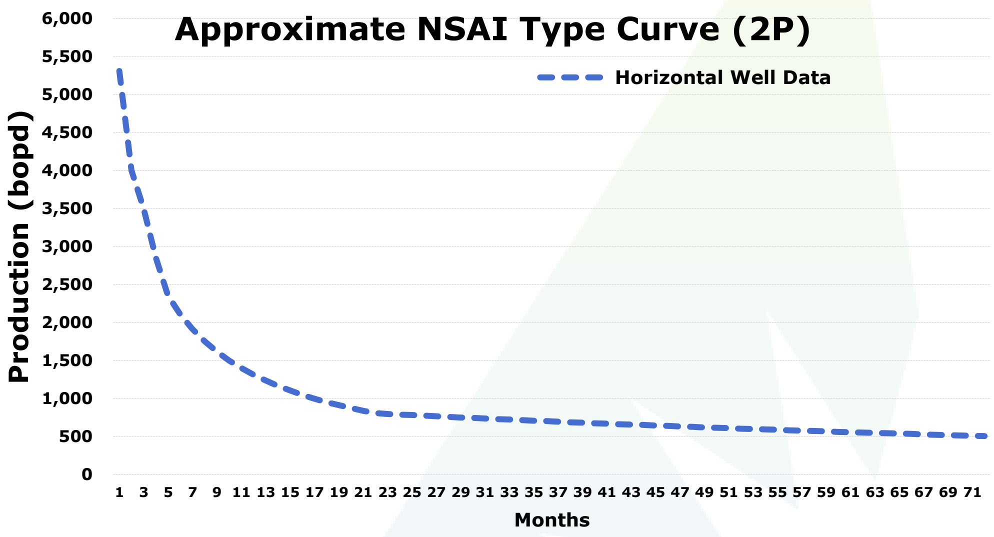
- > 18 million barrels produced until Mar 31, 2024
- Wells drilled since 5H are approaching 2.0 years of normalized producing life and have delivered nearly 12 million barrels of oil
- The Company's average producing well has generated 1 million bbls over the first 20 months of normalized time

Well	Normalized Time [1] (months)	Cuml. Oil (bbls)	Well Payout (# of times)
1XD	35.9	668,771	>5x
2XD	34.2	969,572	>5x
3D	34.0	849,268	>5x
BN-1	32.9	837,176	>5x
4H	34.5	1,480,795	4.0x
5H	31.7	1,777,210	5.0x
6H	19.9	863,262	2.6x
7D	22.2	840,080	2.2x
8H	20.0	1,950,470	4.9x
9H	20.0	1,452,064	3.8x
10H	18.7	1,536,074	3.9x
11H	14.2	1,619,289	3.9x
13H	12.4	853,526	2.0x
12H	11.2	921,721	2.1x
14H	8.8	662,857	1.7x
15H	5.3	715,472	1.7x
16H	2.4	228,775	0.8x
17H	0.8	88,369	0.2x
Total		**18,314,751**	

(1) Normalized time – continuous operating time added together excluding downtime

Type Curve Profile



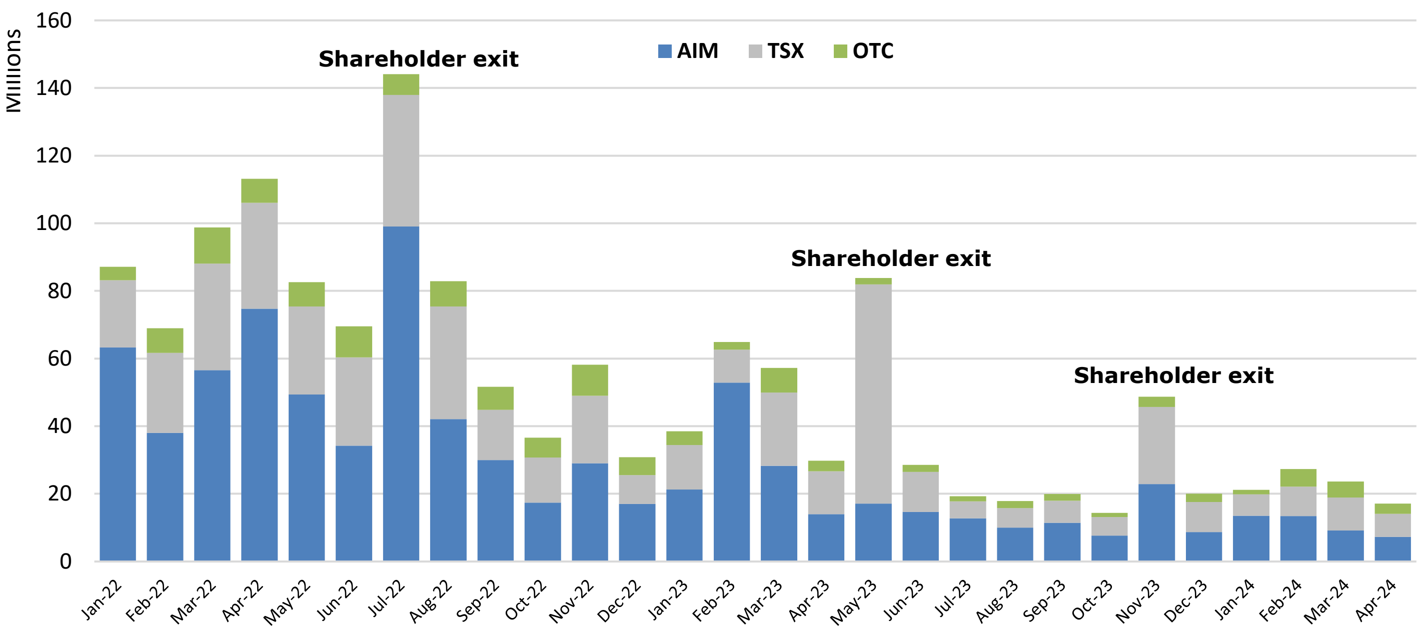


Summary	Horizontal (based on actual data)	Estimated 2P Ave (NSAI)	Deviated (based on actual data)
IP 90 (bopd)	4,900	3,830	2,019
IP 180 (bopd)	3,400	3,000	1,652
IP 365 (bopd)	2,600	2,290	1,300
EUR (mmbbl)	N/A	4.5	N/A
Capex ($ millions)	$14-$15	$14	$8-$10
Capital intensity (180 days)	$4,200	$4,667	$5,400
Payout ($80 Brent)	60-70 days	170 days	60-70 days
Profit to investment ratio	N/A	>5x	N/A

- Actual portfolio average horizontal data would indicate over performance of NSAI 2P type curve. Horizontal portfolio has recycled back its investment 3.7x in ~12 months of normalized production time
- Technical team to forecast production using near 2P performance with additional risks applied
- Robust economics and payout ratios at current Brent levels to justify continued development of 2P/3P booked locations

Share Price and Trading Summary

Tal and PTAL Total Trading Volume by Month (millions of shares)



Major shareholders	Shares owned	%
YF Finance	152,879,100	16.7%
Kite Lake	115,513,226	12.6%
Encompass	64,465,522	7.1%
Fidelity International	59,001,403	6.5%
Meridian Capital	54,668,057	6.0%
Total Basic Shares (May 3, 2024)	**914,927,048**	

PetroTal Share Price History (USD/share)

Extensive Facility Investments in Place

Significant Scalable Infrastructure in Place

- Investment of >$100 million achieves installed processing **capacity of ~24,000 bopd**
- Full field Environmental Impact Assessment (EIA) approved for continued development
  - Common well pad **minimizes footprint (11 hectares, 27 acres)** and increases efficiencies
  - Facility riverside location simplifies logistics
- **Can execute an alternative paced 2P program** with current infrastructure and additional water disposal
- Power generation fuelled by crude oil instead of diesel resulted in **+$100 million NPV(10)**

Facility Build History

Capacity Stage	Incremental Oil bopd	Installation	Incremental Water bwpd
Long-Term Testing Facility	8,000	Dec 2018	10,000
Central Processing Facility #1	8,000	Dec 2019	40,000
Central Processing Facility #2&3	8,000	Dec 2021 & Sept 2023	70,000
Central Processing Facility #3	N/A	Year end 2024	20,000
Total	**24,000**		**140,000**

Peruvian Operating Landscape

Rule of law

- Supreme decree governed contracts carried through regime changes
- International arbitration resolution

Investor friendly fiscal policy

- Second largest mining sector in world
- Favorable royalty rates and social profit sharing (7-8% at 20,000 bopd)
- Tax rate of 32% plus a 5% employee profit tax
- Opex and Capex write offs including tax merger optimizations

Socially friendly distribution

- Oct 20, 2023, Peruvian congress voted in favour of new canon distribution law to reallocate 40% of canon payment to the producing provinces and municipalities
- Approved 2.5% social trust for Block 95 where PetroTal funds and influences the development of community and social related projects

$6 billion Talara refinery completed

- Materially increasing demand for in country produced crude creating pipeline stability
- Attracting international capital and favorable commercial opportunities
- 90,000 bopd refining capacity
- Lack of significant in country producers creates unique expansion opportunities

Executive

President – Dina Boluarte (2022) (Independent with right weighted alignment)

Prime Minister – Gustavo Adrianzen

17 Ministries

Minister of Energy and Mines – Romulo Mucho Mamani

Legislature

Congress

Judiciary

Courts

See footnotes for additional details and definitions

Peruvian Economy and Key State Owned Entities

BBB- Stable (S&P)

- Recent downgrade related to Petroperu's liquidity position
- Still top decile in Latin America

Peruvian economy expanded 3% in 2023

- Beat expectations of 2.1% from worst recession in 33 years

$1.6 billion injection in Petroperu

- Capital injection by Peruvian government to support liquidity
- Backstopping Talara refinery operations and prioritizing energy needs

Successful new entrants into Peru

- Altamesa approved to partner with Petroperu in Block 192
- Qualified late in 2023

Petroperu

- State owned energy entity
- Energy operations entity in Peru
- Owns pipelines, refining, producing fields, distribution and marketing centers, and other energy related infrastructure
- Key counterparty for PetroTal's ONP offtake and related Bayovar marketing activities

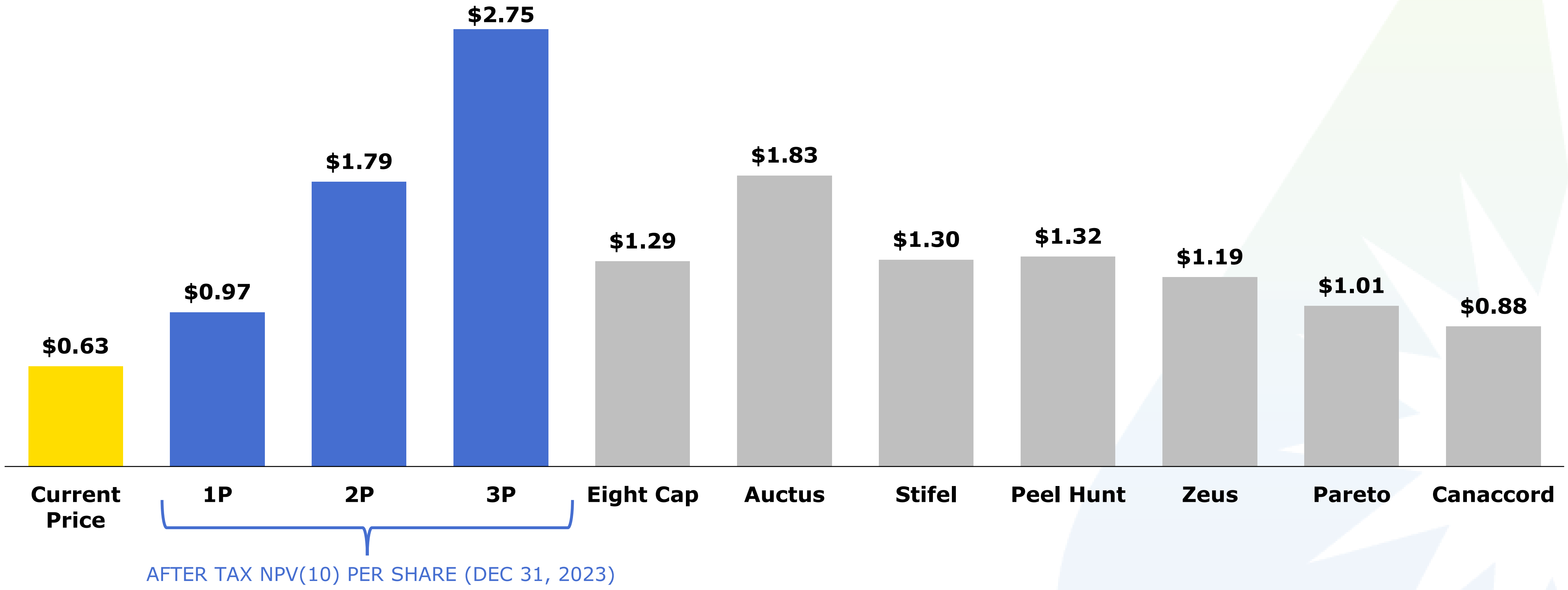
Perupetro

- State owned energy entity
- Contracts and compliance entity in Peru
- Responsible for negotiating contracts, promoting investment, broker royalty payments to the Peruvian treasury, and to propose policy to the Minister of Energy of Mines
- To lead compliance related to environmental preservation

See footnotes for additional details and definitions

Analyst Coverage and Relative Target Valuation

TAL valuation and analyst target summary (USD/share)



Key Highlights

- Trading just over blowdown valuation (PDP valuation NPV10/share) per the Dec 31, 2023 year ended NSAI reserve report
- New investors can obtain 1P, 2P and 3P value for free by investing in PetroTal
- Average analyst target price at USD$1.26/share

Footnotes

Slide 2
1. Market capitalization as of April 22, 2024 using a 1.34 CAD/USD exchange rate
2. Cash less debt = Total cash less short- and long-term debt and lease liabilities
3. NSAI Reserves statement effective date December 31, 2023
4. Reflects contracted offtake of 1,300-2,000 bopd
5. PetroTal also holds a 100% WI in the high impact exploration onshore Block 107
6. See disclaimers – Non Gaap financial measures

Slide 3 / 19
1. Source – 2022 Sustainability Report

Slide 4
1. Production quoted in bopd is average for the year indicated
2. Adjusted EBITDA is NOI (net operating income)less G&A included realized derivative gains/losses

Slide 5
1. All reserve report references are per NSAI Reserves statement effective December 31, 2023. Recovery factors include historical production on top of estimate reserves (ultimate recovery)
2. NSAI reserve production profile does not reflect management's forecast and or budgeted production

Slide 7
1. Soft cap on buybacks refers to an estimated $3 million per quarter of possible buybacks approved by the Company's board
2. Cash sweep refers to the Company's ability to return liquidity to shareholders in excess of approximately $66 million which will also consider future capital and or working capital needs
3. All dividends and buybacks subject to board approval

Slide 8
1. Per the NSAI Reserves statement effective date 31 December 2023
2. AICD – Autonomous Inflow Control Devices

Slide 9
1. With CPF-2, Bretaña has 90k bbl of crude storage
2. Up to eighteen barges available between 10k and 30k bbls capacity to supply ONP and Iquitos refinery
3. Iquitos and Brazil offtake capacity markets are on a monthly basis, thus allowing for maximum recurring sales of 20,000-24,000 bopd of average production assuming no issues at the Puinahua Channel or in the field (high river levels)
4. In development routes are subject to Petroperu approvals and additional investment in required facility investments

Slide 10
1. Average Brent assumed at. Brazil commercial contract specifies Brent + 3 month pricing. Saramuro commercial contract specifies Brent + 8 month pricing (data not shown because not operational)
2. Production allocations by sales route are estimated and subject to material change depending on market conditions
3. Differential is estimated and subject to changes
4. Normalized EBITDA defined as Netback less G&A excluding material non recurring items (one time items) (See disclaimers non gaap financial measures)
5. 2024 G&A includes additional employee headcount
6. See disclaimers – Non Gaap financial measures

Footnotes, *continued*

Slides 12 - 15
READER ADVISORIES and DISCLAIMERS

FORWARD-LOOKING STATEMENTS: This presentation contains certain forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities laws. Forward-looking statements are often, but not always, identified by the use of words such as "guidance", "outlook", "anticipate", "target", "plan", "continue", "intend", "consider", "estimate", "expect", "may", "will", "should", "could" or similar words suggesting future outcomes. More particularly, this press release contains statements concerning: PetroTal's business strategy, objectives, strength and focus; the Acquisition; satisfaction or waiver of the closing conditions to the Acquisition; receipt of required regulatory approvals for the completion of the Acquisition; the purchase price of the Acquisition net closing adjustments; the anticipated benefits of the Acquisition, including the impact of the Acquisition on the Company's operations, reserves, inventory and opportunities, financial condition and overall strategy; expectations with respect to reserves, oil production levels, decline rates, abandonment and reclamation obligations, cash flow, EBITDA and valuation related to the Assets and PetroTal following the Acquisition; development and drilling plans for the Assets.

The forward-looking statements are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning: the business plan of PetroTal, CEPSA Peru and the Assets; the receipt of all approvals and satisfaction of all conditions to the completion of the Acquisition; the timing of and success of future drilling, development and completion activities; the geological characteristics of PetroTal's properties; the characteristics of the Assets; the successful integration of the Assets into PetroTal's operations; the ability of existing infrastructure to deliver production and the anticipated capital expenditures associated therewith, the ability of government groups to effectively achieve objectives in respect of reducing social conflict and collaborating towards continued investment in the energy sector, including pursuant to Acta, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal's products, including pursuant to hedging arrangements, the availability and performance of drilling rigs, facilities, pipelines, other oilfield services and skilled labour, royalty regimes and exchange rates, the impact of inflation on costs, the application of regulatory and licensing requirements, the accuracy of PetroTal's geological interpretation of its drilling and land opportunities, current legislation, receipt of required regulatory approval, the success of future drilling and development activities, the performance of new wells, future river water levels, the Company's growth strategy, general economic conditions and availability of required equipment and services.

Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with: counterparty risk to closing the Acquisition; unforeseen difficulties in integrating the Assets into PetroTal's operations; incorrect assessments of the value of benefits to be obtained from acquisitions and exploration and development programs (including the Acquisition); the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety and environmental risks), commodity price volatility, price differentials and the actual prices received for products, exchange rate fluctuations, legal, political and economic instability in Peru, access to transportation routes and markets for the Company's production, changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system; and wars (including Russia's war in Ukraine). Please refer to the risk factors identified in the Company's most recent AIF and MD&A which are available on SEDAR+ at www.sedarplus.ca. The forward-looking statements contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") prospective results of operations and production, guidance, EBITDA and components thereof, including pro forma the completion of the Acquisition, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this document was approved by management as of the date of this document and was provided for the purpose of providing further information about PetroTal's future business operations. PetroTal and its management believe that FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. PetroTal disclaims any intention or obligation to update or revise any FOFI contained in this document, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this document should not be used for purposes other than for which it is disclosed herein. Changes in forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in PetroTal's guidance. The Company's actual results may differ materially from these estimates.

OIL REFERENCES: All references to "oil" or "crude oil" production, revenue or sales in this press release mean "light crude oil" as defined in NI 51-101. All references to Brent indicate Intercontinental Exchange Brent.

RESERVES AND FUTURE NET REVENUE DISCLOSURE. All reserves values, future net revenue and ancillary information contained in this press release relating to Assets are derived from the Reserves Report unless otherwise noted. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to the effect of aggregation. There is no assurance that the forecast price and cost assumptions applied by NSAI in evaluating PetroTal' reserves will be attained and variances could be material.

All evaluations and summaries of future net revenue are stated prior to the provision for interest, debt service charges or general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. The recovery and reserve estimates of PetroTal' crude oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil reserves may be greater than or less than the estimates provided herein. There are numerous uncertainties inherent in estimating quantities of crude oil, reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved 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 plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. Proved 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. 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 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. Certain terms used in this press release but not defined are defined in NI 51-101, CSA Staff Notice 51-324 – Revised Glossary to NI 51-101, Revised Glossary to NI 51-101, Standards of Disclosure for Oil and Gas Activities ("CSA Staff Notice 51-324") and/or the COGEH and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 and the COGEH, as the case may be.

SPECIFIED FINANCIAL MEASURES: This press release includes various specified financial measures, including non-GAAP financial measures, non-GAAP financial ratios and capital management measures such as "Netback" and "EBITDA". These measures do not have a standardized meaning prescribed by generally accepted accounting principles ("GAAP") and, therefore, may not be comparable with the calculation of similar measures. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures. "Netback" (non-GAAP financial measure) equals total petroleum sales less quality discount, lifting costs, transportation costs and royalty payments calculated on a bbl basis. The Company considers netbacks to be a key measure as they demonstrate Company's profitability relative to current commodity prices. "EBITDA" (non-GAAP financial measure) is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization and adjusted for G&A impacts and certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses, including derivative true-up settlements. PetroTal utilizes EBITDA as a measure of operational performance and cash flow generating capability. EBITDA impacts the level and extent of funding for capital projects investments. Please refer to the Company's most recent management's discussion and analysis for additional information relating to specified financial measures.

Footnotes, *continued*

Slide 16-19
1. Production, capex, and cash flow profiles are internal management estimates and have not been confirmed or reviewed by a third party reserve evaluator. They are subject to change at any time as new assumptions are contemplated
2. See disclaimers (Non Gaap financial measures)
3. Assumes license contract ends in 2041 but is extended for Block 95 and 107 expansion opportunities
4. Assumes $80/bbl on a long term average basis

Slide 20
1. SDG refers to the United Nation's 17 goals for sustainable development (www.sdgs.un.org/goals)

Slide 24/25
1. Normalized time adds all hours of well operations together as if the wells were producing continuously to eliminate the impact of social and technical downtime
2. Cumulative NOI (net operating income)(see disclaimers – Non Gaap financial measures) is estimated based on financial statement netbacks at approximately the time of operation

Slide 26
1. Shareholders per May 4 2024 (AIM rule 26 per PetroTal website)
2. Trading data source per TSX, OTC QX and AIM ending Mar 2024 (1.34 CAD/USD)
3. On Nov 26, 2021 GTE sold an aggregate of 137,093,750 common shares in PetroTal

Slide 27
1. Includes associated infrastructure spending to CPF-2, such as power generation using crude oil as feedstock that helps lower lifting costs
2. When considering the Dec 31, 2023 3P volumes in the reserve report, additional injection capacity equipment is required

Slide 28/29
1. Sources – Peruvian government websites and S&P global

Slide 30
1. CAD/USD = 1.34 and CAD/GBP = 1.7

Disclaimers

Disclaimers, *continued*

OTHER READER ADVISORIES

FORWARD-LOOKING STATEMENTS: This press release contains certain statements that may be deemed to be forward-looking statements. Such statements relate to possible future events. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "expect", "plan", "estimate", "potential", "will", "should", "continue", "may", "objective" and similar expressions. Without limitation, this press release contains forward-looking statements pertaining to: PetroTal's intention to continue to develop the Bretana asset; the targeted 20% growth rate from 2023; PetroTal's forecast 2024 funds flow of $160 million; plans with respect to the Company's seismic program in the southern part of Block 95 including with respect to its intended duration and purposes; PetroTal's intentions to continue seeking a partner for co-investment for Block 107 and obtain development permits; the positioning of the Company in 2024; PetroTal's intentions with respect to its return of capital program (including that it will maintain a 12% yield and that the program will continue to consist of dividends at $0.015/share and buybacks of approximately $1.0 million/month in accordance with the Company's return of capital policy); PetroTal's plans to commercialize new sales routes through the OCP in Ecuador and through Yurimaguas to Bayovar and the anticipated benefits therefrom (including in respect of production estimates) and the timing thereof; expectations surrounding the Company's 2.5% social fund including PetroTal's intended capital allocation of $9 million towards the fund; PetroTal's plans to dril a water disposal well in 2024 and expectations regarding capacity within the Company's existing water disposal wells throughout 2024; estimated returns from the Company's 2024 dividend and buyback plan; drilling plans including with respect to the commencement and completion of drilling wells 17H, 18H, and 19H; intentions regarding well 17H, including in respect of timing and budgetary expectations; estimated payback from well 16H and the timing thereof; PetroTal's plans to continue to allocate capital to its long term preventative erosion control program; PetroTal's 2024 budget for the erosion control project and plans in respect thereof; the 2024 Capex budget; plans with respect to PetroTal's 2024 facilities program including anticipated key projects and expenditures in respect thereof; and PetroTal's expectations regarding 2024 operating costs. In addition, statements relating to expected production, reserves, recovery, replacement, costs and valuation are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. The forward-looking statements are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the ability of existing infrastructure to deliver production and the anticipated capital expenditures associated therewith, the ability to obtain necessary permits, the ability of government groups to effectively achieve objectives in respect of reducing social conflict and collaborating towards continued investment in the energy sector, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal's products, including pursuant to hedging arrangements, the availability and performance of drilling rigs, facilities, pipelines, other oilfield services and skilled labour, royalty regimes and exchange rates, the impact of inflation on costs, the application of regulatory and licensing requirements, the accuracy of PetroTal's geological interpretation of its drilling and land opportunities, current legislation, receipt of required regulatory approval, the success of future drilling and development activities, the performance of new wells, future river water levels, the Company's growth strategy, general economic conditions and availability of required equipment and services. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety and environmental risks), commodity price volatility, price differentials and the actual prices received for products, exchange rate fluctuations, legal, political and economic instability in Peru, access to transportation routes and markets for the Company's production, changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system; and wars (including Russia's war in Ukraine, the Israeli- Hamas conflict and the Houthis attacks in the Red Sea). Please refer to the risk factors identified in the Company's most recent annual information form and management's discussion and analysis (the "MD&A") which are available on SEDAR+ at www.sedarplus.ca. The forward-looking statements contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. Forward looking CAPEX and OPEX assumptions in this presentation are consistent with the NSAI Reserve Report as of Dec 31, 2023 and current historical operating results to date, however, the timing and pace of the development plan has been adjusted from the NSAI Report to align with management's internal view on commodity price and liquidity. Management may create and post alternative development cases at their discretion and label them internal.

SHORT-TERM RESULTS: References in this press release to peak production rates, current production rates, initial 14-day production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for PetroTal. The Company cautions that such results should be considered to be preliminary.

OIL REFERENCES: All references to "oil" or "crude oil" production, revenue or sales in this press release mean "heavy crude oil" as defined in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

SPECIFIED FINANCIAL MEASURES: This press release includes various specified financial measures, including non-GAAP financial measures, non-GAAP financial ratios and capital management measures such as "Netback", "EBITDA", "Adjusted EBITDA", "Net Operating Income" and "free funds flow". These measures do not have a standardized meaning prescribed by generally accepted accounting principles ("GAAP") and, therefore, may not be comparable with the calculation of similar measures. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures. "Netback" (non-GAAP financial measure) equals total petroleum sales less quality discount, lifting costs, transportation costs and royalty payments calculated on a bbl basis. The Company considers netbacks to be a key measure as they demonstrate Company's profitability relative to current commodity prices. "EBITDA" (non-GAAP financial measure) is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization and adjusted for G&A impacts and certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses, including derivative true-up settlements. PetroTal utilizes EBITDA as a measure of operational performance and cash flow generating capability. EBITDA impacts the level and extent of funding for capital projects investments. "Adjusted EBITDA" (non-GAAP financial measure) is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization and adjusted for G&A impacts and certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses, including derivative true-up settlements. PetroTal utilizes adjusted EBITDA as a measure of operational performance and cash flow generating capability. Adjusted EBITDA impacts the level and extent of funding for capital projects investments. Reference to EBITDA is calculated as net operating income less G&A. "Net Operating Income" (non-GAAP financial measure) is calculated as revenues less royalties, operating expenses, and direct transportation. The Company considers Net Operating Income measure as they demonstrate Company's profitability relative to current commodity prices. "Free funds flow" (non-GAAP financial measure) is calculated as net operating income less G&A less exploration and development capital expenditures less realized derivative gains/losses and is calculated prior to all debt service, taxes, lease payments, hedge costs, factoring, and lease payments. Management uses free funds flow to determine the amount of funds available to the Company for future capital allocation decisions. Please refer to the MD&A for additional information relating to specified financial measures.

FOFI DISCLOSURE: This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about PetroTal's 2024 fully funded budget and guidance, prospective results of operations, estimated growth rate, 2024 targets (including production and sales targets), 2024 average sales target of 17,000 bopd, initial 14 day production rate for well 16H of 6,000 bopd, production capacity, forecast funds flow of $160 million, free funds flow of $25 million and the components thereof including dividends and share buybacks and the targeted 12% return therefrom as well as derivative true up payments, erosion control and community expense, revenue, capex, average contracted brent, EBITDA, adjusted EBITDA, estimated closing 2024 cash and components thereof including estimated net working capital movements, forecast 2024 funds flow, free funds flow, free funds flow (after capex), payout of wells, estimated payback, netback, OPEX and the components thereof, G&A expenses and the components thereof, tax rates, Capex, royalty rates, future investments and capital allocation (including capital deployed towards any government and community amounts in 2024 such as the 2.5% social fund), net operating income, shareholder returns and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this press release was approved by management as of the date of this press release and was included for the purpose of providing further information about PetroTal's anticipated future business operations. PetroTal disclaims any intention or obligation to update or revise any FOFI contained in this press release, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein. All FOFI contained in this press release complies with the requirements of Canadian securities legislation, including NI 51-101. Changes in forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in PetroTal's guidance. The Company's actual results may differ materially from these estimates.

Disclaimers, *continued*

Oil and Gas Advisories

Crude Oil. All references to “oil” or “crude oil” production, revenue or sales mean “heavy crude oil” as defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). Brent refers to Intercontinental Exchange “ICE” Brent.

Reserves Disclosure. The reserve estimates contained herein were derived from a reserves assessment and evaluation prepared by Netherland Sewell & Associates, Inc. (“NSAI”), a qualified independent reserves evaluator, with an effective date of December 31, 2023 (the “NSAI Reserves Report”). The NSAI Reserves Report has been prepared in accordance with definitions, standards and procedures contained in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook (the “COGE Handbook”). The reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Volumes of reserves have been presented based on a company interest. Readers should give attention to the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each category as explained herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Resources Disclosure. The prospective resource estimates contained herein were derived from a resource assessment and evaluation prepared by NSAI, a qualified independent reserves evaluator, with an effective date of June 30, 2020 (the “NSAI Resources Report”). The NSAI Resources Report has been prepared in accordance with definitions, standards and procedures contained in NI 51-101 and the COGE Handbook. Prospective resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. All of the prospective resources have been classified as light oil with a gravity of 46 degrees API. There is uncertainty that it will be commercially viable to produce any portion of the resources in the event that it is discovered. “Unrisked Prospective Resources” are 100% of the volumes estimated to be recoverable from the field in the event that it is discovered and developed. NSAI has determined that a 16% chance of discovery is appropriate for the prospective resources based on an assessment of a number of criteria. The estimates of prospective resources provided in this presentation are estimates only and there is no guarantee that the estimated prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated. Not only are such prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates herein. The prospective resources estimates that are referred to herein are risked as to chance of discovery. Risks that could impact the chance of discovery include, without limitation, geological uncertainty, political and social issues, and availability of capital. In general, the significant factors that may change the prospective resources estimates include further delineation drilling, which could change the estimates either positively or negatively, future technology improvements, which would positively affect the estimates, and additional processing capacity that could affect the volumes recoverable or type of production. Additional facility design work, development plans, reservoir studies and delineation drilling is expected to be completed by PetroTal in accordance with its long-term resource development plan.

Reserve Categories. Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves (1P) are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves (2P) 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 plus probable reserves. Possible reserves (3P) are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Resource Categories. Prospective resources are classified according to the degree of certainty associated with the estimates. The following classification of prospective resources used in the presentation: Low Estimate (or 1C) means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate. Best Estimate (or 2C) means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate. High Estimate (or 3C) means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

BOE Disclosure. The term barrels of oil equivalent (“BOE”) may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel (6Mcf/bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All BOE conversions in the report are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil.

Analogous Information. Certain information in this document may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas, wells and/or operations that are in geographical proximity to or on-trend with lands held by PetroTal and production information related to wells that are believed to be on trend with PetroTal's properties. Such information has been obtained from government sources, regulatory agencies or other industry participants. Management of PetroTal believes the information may be relevant to help define the reservoir characteristics in which PetroTal may hold an interest and such information has been presented to help demonstrate the basis for PetroTal's business plans and strategies.

However, to PetroTal’s knowledge, such analogous information has not been prepared in accordance with NI 51-101 and the COGE Handbook and PetroTal is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. PetroTal has no way of verifying the accuracy of such information. There is no certainty that the results of the analogous information or inferred thereby will be achieved by PetroTal and such information should not be construed as an estimate of future production levels. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by PetroTal and there is no certainty that the reservoir data and economics information for the lands held or to be held by PetroTal will be similar to the information presented herein. The reader is cautioned that the data relied upon by PetroTal may be in error and/or may not be analogous to such lands to be held by PetroTal.

Disclaimers, *continued*

Initial Production Rates. Any references in this document to test rates, flow rates, initial and/or final raw test or production rates, early production, test volumes and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not necessarily indicative of long-term performance or of ultimate recovery. Such rates may also include recovered "load" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for PetroTal. In addition, the resource play which may be subject to high initial decline rates. Such rates may be estimated based on other third party estimates or limited data available at this time and are not determinative of the rates at which such wells will continue production and decline thereafter.

Type Curves. Certain type curves disclosure presented herein represent estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The type curves represent what management thinks an average well will achieve. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells.

OOIP Disclosure. The term original-oil-in-place ("OOIP") is equivalent to total petroleum initially-in-place ("TPIIP"). TPIIP, as defined in the COGE Handbook, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. 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. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered.

US Disclaimer. This presentation is not an offer of the securities for sale in the United States. The securities have not been registered under the U.S. Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an exemption from registration. This presentation shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

Mean Estimate. Represents the arithmetic average of the expected recoverable volume. It is the most accurate single point representation of the volume distribution.

All figures in US dollars unless otherwise denoted.

Disclaimers, *continued*

Non-GAAP Financial Measures, Oil and Gas Metrics and Other Key Performance Indicators

This presentation contains certain financial measures, as described below, which do not have standardized meanings prescribed by generally accepted accounting principles (“GAAP”). In addition, this presentation contains metrics commonly used in the oil and natural gas industry and other key performance indicators (“KPI”), financial and non-financial, that do not have standardized meanings under the applicable securities legislation. As these non-GAAP financial measures and KPI are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. It should not be assumed that the future net revenues estimated by PetroTal’s independent reserves evaluators represent the fair market value of the reserves, nor should it be assumed that PetroTal’s internally estimated value of its undeveloped land holdings or any estimates referred to herein from third parties represent the fair market value of the lands. These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare PetroTal’s operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes. “Operating netback” is calculated by dividing net operating income by barrels sold in the corresponding period. The Company considers operating netbacks to be a key measure as they demonstrate Company’s profitability relative to current commodity prices. “NPV-10” or similar expressions represents the net present value (net of capex) of net income discounted at 10%, with net income reflecting the indicated oil, liquids and natural gas prices and IP rate, less internal estimates of operating costs and royalties. “Net debt” means long term debt plus derivative obligation plus accounts payable less total cash and accounts receivables.“Enterprise value” is calculated as the market capitalization of the Company plus net debt, where market capitalization is defined as the total number of shares outstanding multiplied by the price per share at a given point in time. “EBITDA” means net operating cash flow less G&A. “CAPEX” means capital expenditures. “IP” means the initial production from a well for a set unit of time. “Capital efficiency” is CAPEX divided by production rate (bopd). “EUR” means estimated ultimate recovery, an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well. EUR is not a defined term within the COGE Handbook and therefore any reference to EUR in this presentation is not deemed to be reported under the requirements of NI 51-101. Readers are cautioned that there is no certainty that the Company will ultimately recover the estimated quantity of oil or gas from such reserves or wells. “FDC” means future development costs. “F&D” means finding and development costs, calculated as the sum of capital expenditures incurred in the period and the change in FDC required to develop reserves. “Operating cash flow” is revenue less royalties less field operating expenses (field netback). “Free cash” or “free funds flow” defined as Adjusted EBITDA before minus CAPEX. “Yield” means free funds flow per year as a percentage of market capitalization. “Half-cycle” means CAPEX related to drilling, completion, and equipping. “Mid-cycle” means half-cycle CAPEX plus costs to acquire land/leases. “IRR” is the internal rate of return, the discount rate required to arrive at an NPV equal to zero. Rates of return set forth in this presentation are for illustrative purposes. There is no guarantee that such rates of return will be achieved in the future. “Recycle ratio” is calculated as operating netback divided by F&D and is a measure for evaluating the effectiveness of the Company’s re-investment program. “Sustaining CAPEX” is the estimated capital required to bring on new production which offsets the natural decline of the existing production and keeps the year-over-year production flat.

Abbreviations

Bbl	Barrel
bopd	barrel of oil per day
k bopd	Thousand barrel of oil per day
F&D	Finding and development costs
NIBD	Net interest bearing debt
Mmbbl	Million barrels of oil
NGL	Natural gas liquids
bbo	Billion barrels of oil
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
Free Funds/Cash Flow	Adjusted EBITDA less CAPEX or as defined in footnotes
FFO	Funds flow from operations
Adj. EBITDA	Earnings before interest, taxes, depreciation, amortization, and after derivative adjustments; EBITDA is Adj. EBITDA prior to derivative impacts
Normalized EBITDA	EBITDA excluding material one time non recurring expenses
Ha	Hectares
PDP	Proved Developed Producing Reserves
1P	Proved Reserves
2P	Proved + Probable Reserves
3P	Proved + Probable + Possible Reserves

PetroTal