PetroTal

May 26, 2022

Investor Webcast

Q1 2022 Results

Corporate Overview

PetroTal corporate and technical summary (USD millions)[1-6]

Corporate Summary	
Share price (May 23, 2022)	$0.62 (CAD)
Basic share count (millions)	837
Market cap ($1.28 CAD/USD)	$405 (USD)
Net debt (cash)	($9)
Enterprise value	$396
EV/2022 EBITDA	1.2x
Tax pools (2022 estimated)	$280 Peru / $70 Canada
Technical Summary	
Current production (May 1 – 23 2022)	~15,700 bopd
2022 production guidance	15,000 – 16,000 bopd
2P reserves	78 mmbbls
2P after tax NPV(10)	$1 billion ($1.2/share)
2P / 3P booked well count	22 / 29
Current producing well count	11
Commercial Summary	
Bretaña field storage capacity	90,000 bbls
Iquitos sales capacity	1,300 – 2,000 bopd
Brazil sales capacity	11,500 – 16,500 bopd
ONP sales capacity (Peruvian pipeline)	25,000 bopd
CPF-2 oil processing capacity	Up to 26,000 bopd

Assets and key offtake locations

See presentation footnotes in appendix

Delivering our value proposition

Simultaneous growth and yield without overcapitalization

Asset running room[1]

+11 wells 2P (~3 years drilling)

+18 wells 3P (~5 years drilling)

Unbooked infill locations

Other 100% WI short investment cycle owned areas

Best in class capital efficiency[2]

<$5,000 per flowing bbl IP 365

Total capex deployed of ~$250 million since inception

Management deliverables

ESG leadership in Peru

Robust heavy oil margins

Bretaña direct opex ~$13-$15/bbl

Scalable fixed costs

< 30 day paybacks achieved

$12-$14 million/well

+$80/bbl Brent

Natural waterflood pressure support

water driven reservoir

constant pressure support

Company History

0 to 958 bopd[1]
Source asset and initial capitalization an asset prep

4,131 bopd
Demonstrated operational credibility

5,675 bopd
Recalibration and alignment due to COVID-19

8,956 bopd
Operational excellence (20,000 bopd achieved)

15,500 bopd
Free cash flow focused

Reinstating return of capital policy

2023

Largest crude oil producer in Peru

3x multiple on share price achieved[2]

2017/2018

- Acquired Gran Tierra's Peru business
- Raised $32 million in net equity
- TSXV reverse takeover of Sterling Resources
- Reactivated well 1XD
- Exit production of 1,000 bopd
- Completed infrastructure upgrade to process 5,000 bopd

2019

- Drilled five additional wells and 1 water disposal well
- Exited 2019 at 13,300 bopd
- Secured offtake arrangement with Petroperu
- Raised $23.7 million in net equity

2020

- Drilled 6H well through initial COVID-19 outbreak
- Raised $16.4 million in net equity
- Completed a third route to market strategy through Brazil
- Enacted flexible capex strategies to conserve liquidity and production

2021

- Four development wells
- Accelerated water disposal strategy
- Commissioned CPF-2
- Completed a $100 million 3-year bond issue
- Reached 20,000 bopd in mid December

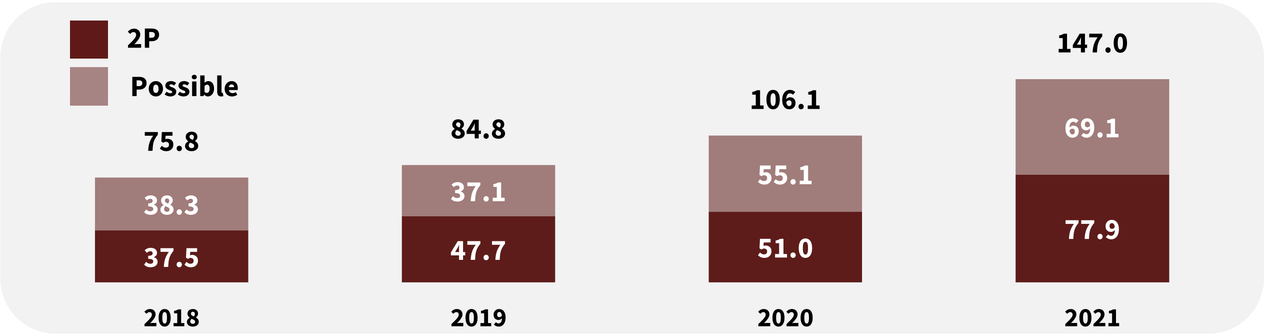
2022

- Four additional producing wells onstream
- ~$230 million in estimated free cash flow pre debt service ($102/bbl contracted Brent)
- Focused on total debt repayment in Q4 2022 or early 2023
- CPF-3 and other expansion facility work

See presentation footnotes in appendix

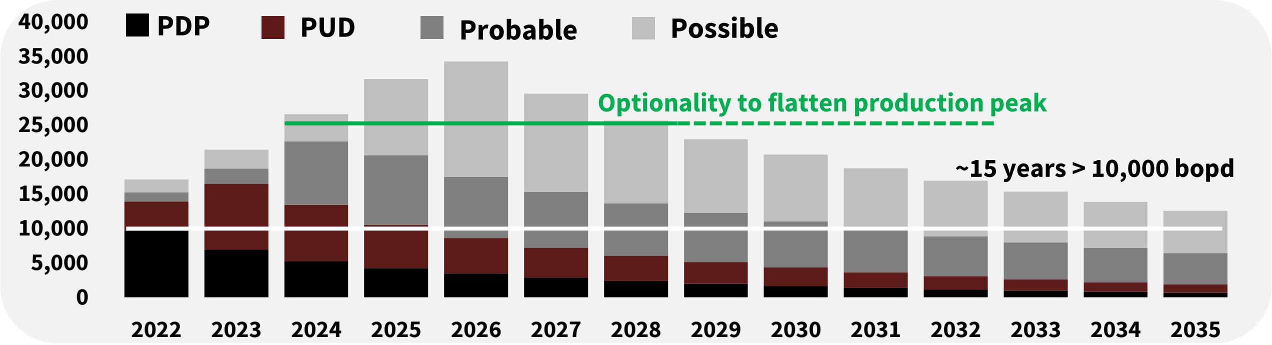
Bretaña Reserves summary

Reserves summary (mmbbl)[1-3]



- 2P and 3P recovery factors of 22% and 25%, delivered in four years from zero production
- Booked 2P well count at 22 wells allowing continuous multi year development programs
- 2021's 2P reserves surpassing 2018's 3P value

NSAI production profile (bopd)



- ~15 years of production > 10,000 bopd under 3P case
- Peak production of 35,000 bopd plausible
- Ability to flatten peak production into multi year production profile of 25,000 bopd

Key reserve metrics1[1-4]

In USD mill	OOIP mmbbl	Reserves mmbbl	Recovery Factor	A-tax NPV(10)	F&D USD millions	F&D/bbl	Recycle Ratio ($65/bbl netback)
1P	247	37	18%	$570	$141	$6.6	10x
2P	389	78	22%	$1,020	$289	$4.7	14x
3P	618	147	25%	$1,653	$504	$3.9	16x

- 2P F&D/bbl < $5.0 generating a recycle ratio of 13x at $100/bbl Brent
- Billion dollar 2P after tax valuation at $75/bbl Brent
- Fundable 3P program out of existing cash flow

ESG Leadership in Peru

Environmental[1]

- ✓ Carbon monitoring quality certificate
- ✓ 2021 carbon footprint of 38,086 tCO_2e (scope 1-2) leading to 11.6 kg of CO_2 per bbl produced in 2021
- ✓ Approval for "Nature for Nature" plan
- ✓ ~11 hectares total field footprint
- ✓ Comprehensive spill prevention programs and training

H&S[1]

- ✓ Zero lost day accidents in 2021 for employees
- ✓ Extensive H&S training for employees and contractors
- ✓ Investments in highest standard PPE
- ✓ Awarded Biosafety Seal award by SGS

For a detailed roadmap on PetroTal's ESG policies, goals, and track record please see our 2020 Sustainability Report posted on website

Social (Shared Values)[1]

- ✓ 2.5% social trust
- ✓ Delivery of agri/aqua educational information and training
- ✓ Ensure transparent communication with authorities, leaders, and local residents with feedback loop
- ✓ Hire local

Governance[1]

Various resolution channels

- ✓ Anti-corruption & crime
- ✓ Complaint resolution process

Policy driven approaches to:

- ✓ Equitable workplace
- ✓ Transparent business conduct
- ✓ Conflict resolution policies
- ✓ Whistle-blower policies

See presentation footnotes in appendix
Carbon footprint subject to final approval or final adjustments

PetroTal facilitates community empowerment

SDG # 3

Medical

Funded and installed X-ray, odontology, maternity ultra sound, and vison related equipment

Nursery ward created

SDG # 4 & 5

Education

> 40 student pre and post grade sponsorships

~3,000 school kits for elementary students

Technology

Computers and IPADS provided to students

SDG # 6,7,9

Water

Clean water management and monitoring facilities

Power

Diesel for power

Solar panel projects

Bridge construction

Significant dock work

Breakwater installations for erosion mitigation

Landmarks

Bretaña library upgrades

Recycling infrastructure

Community centers

SDG # 8

Hire/Train Local

Training for 65 women to manufacture and sell organic fiber products

Trained 28 workers at technical institutes

No expats employed in Peru

Farming & Agriculture

Supply chain support for 420 farmers and their local products

Buyer of excess produce

Job Creation

> 500 temporary jobs created since July 2018

Fishing

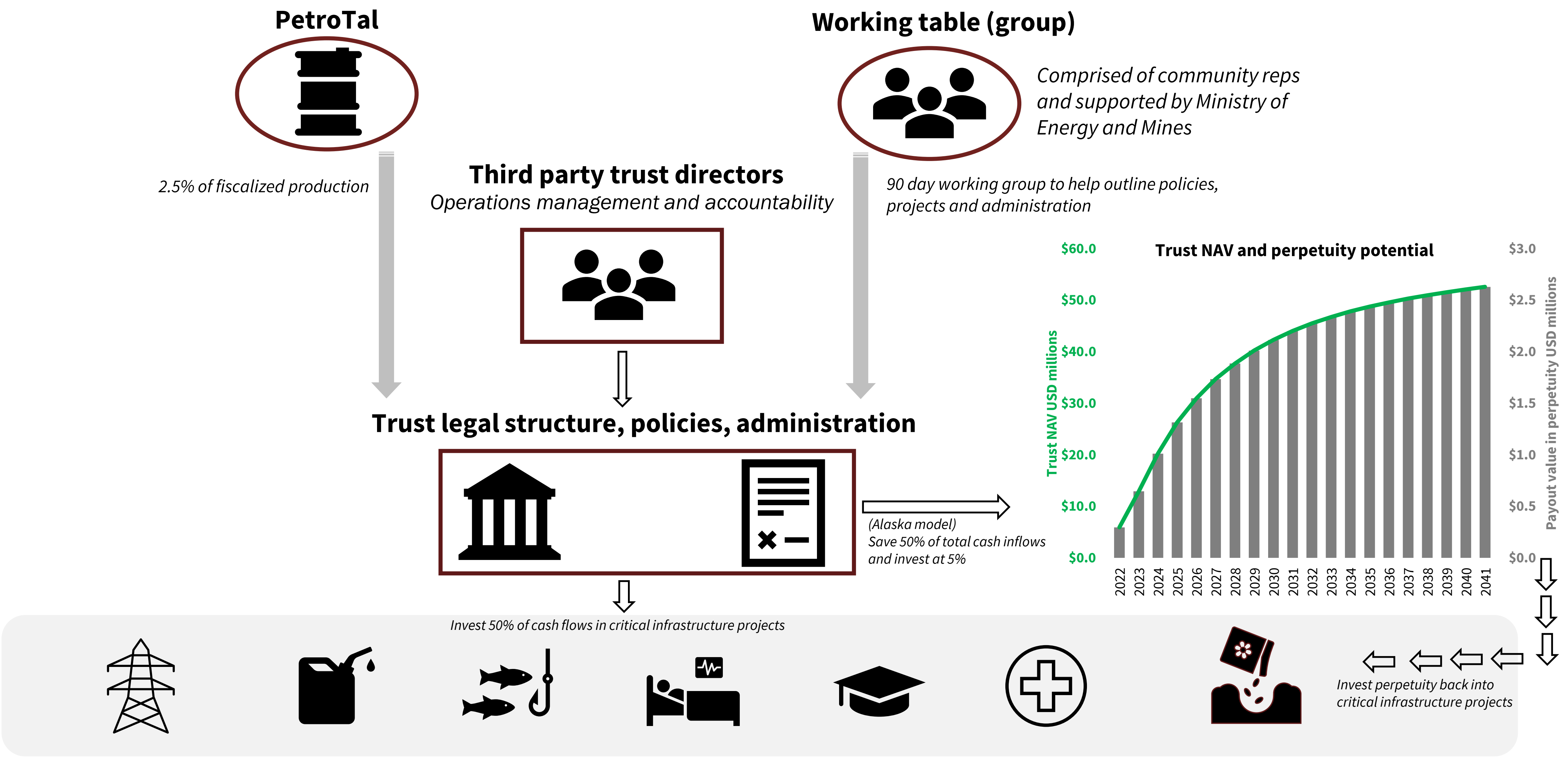
Sustainable fishing projects

Commercial ice makers

Installed fishing cages for fishing projects

SDG = Sustainable Development Goal
Per the UNDP (United Nations Development Program)

PetroTal led solution to social unrest issues

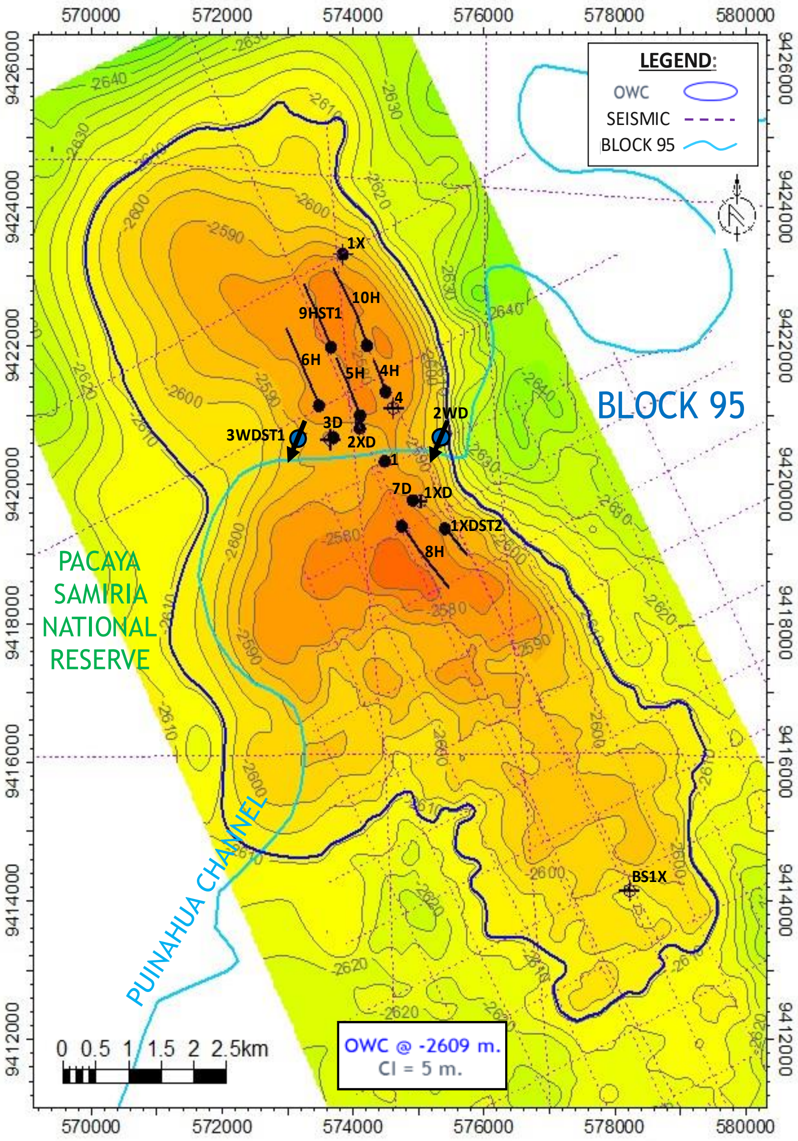


Low risk development plan with solid subsurface characteristics

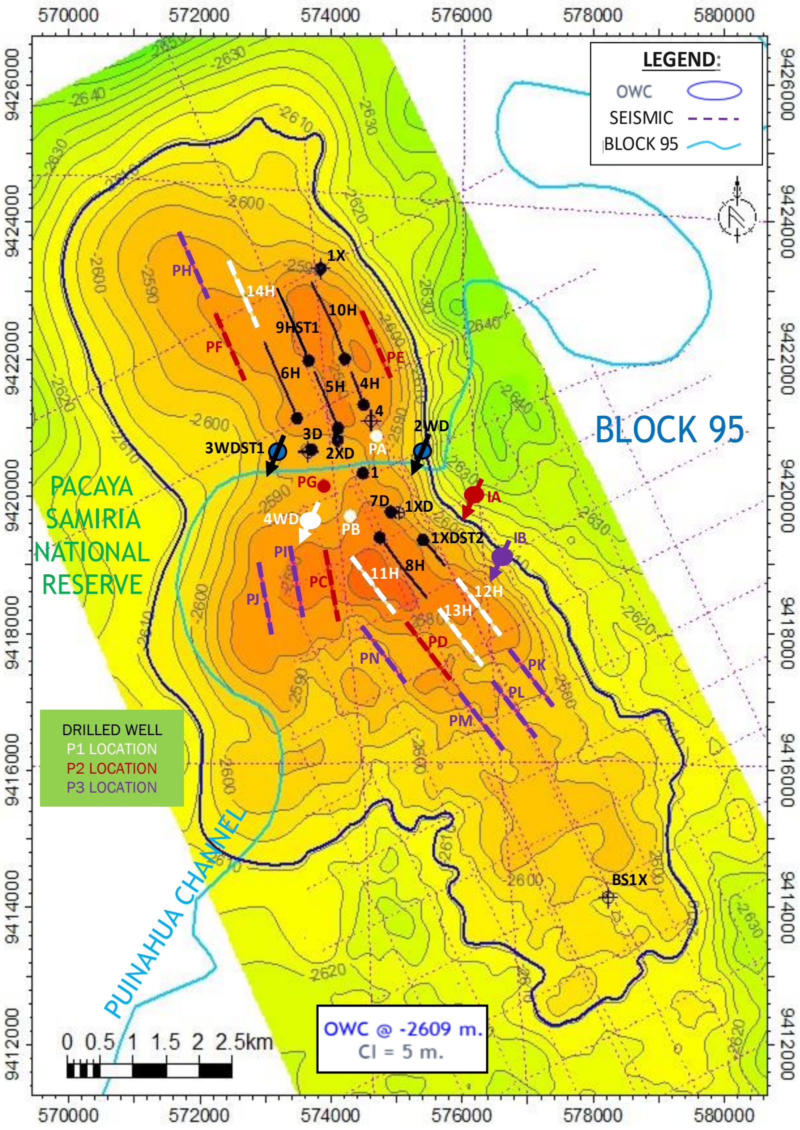
Technical characteristics

- Well defined four-way structure bounded by a reverse fault to the east – prolific geologic trap system
- Field size of 6,000 hectares (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 AICDs[2] technology assures pressure maintenance and high volumes of oil recovery
- Analogous fields in the basin have recovery factors of 22-42% vs Bretaña at 22% - possible Bretaña upside recovery factor of incremental 10-25%
- 3P reserves case has 29 producing wells. Potential exists for further infill drilling and "proving up" probable and possible drilling locations[1]

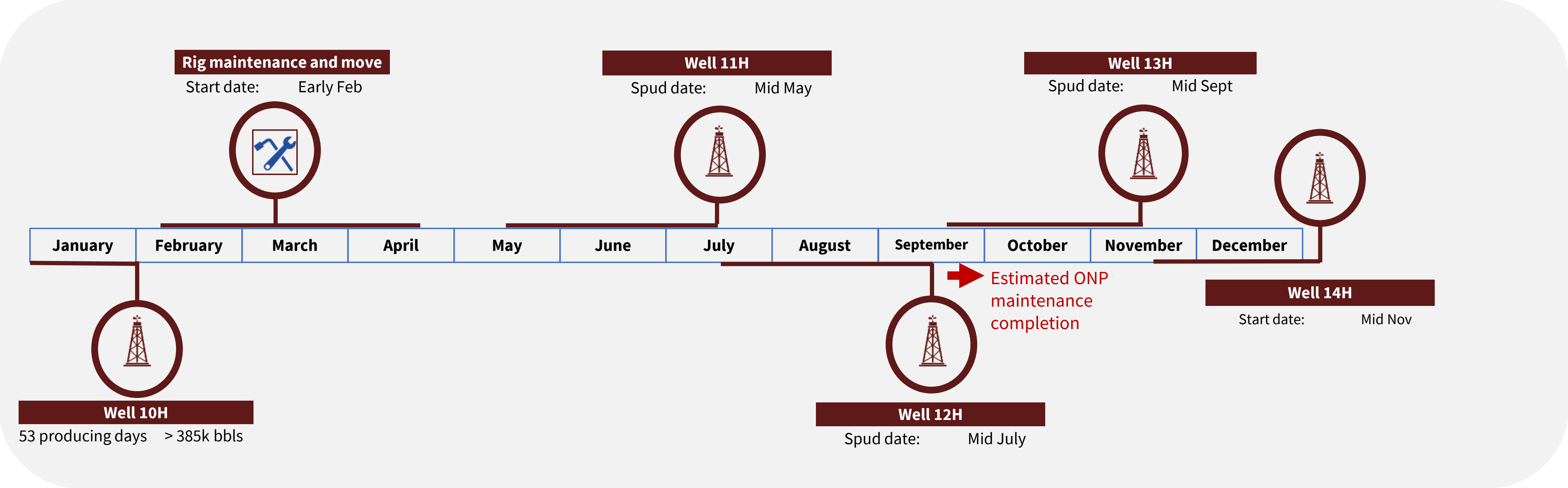
Current drilled locations in structure map



Full field development in structure map[2]



Estimated 2022 forward drilling schedule



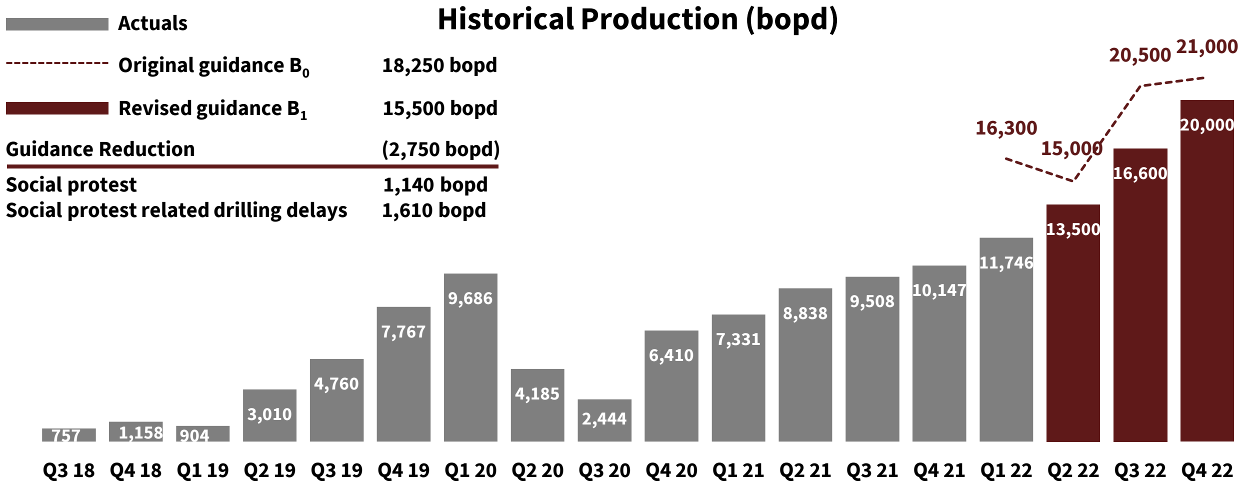
Key highlights[1-3]

- 10H on production in early Feb 2022 and 14H on production in early 2023, with some Capex incurred in 2022
- 11H, 12H, and 13H drilled and put on production in 2022
- Regular rig maintenance early in 2022 ensures optimal drilling performance
- Q4 2022 averaging ~20,000 bopd
- Scheduled flush production forecast in Q4 2022 to coincide with ONP availability

2022 Guidance

Low capital intensity development plan generating robust yield and growth profiles[1-6]

Summary in USD millions	2020	2021	2022 B_0	2022 B_1
	actual	*actual*	*Jan 28*	***May 26***
Production (bopd)	**5,674**	**8,965**	**18,250**	**15,500**
Contracted Brent ($/bbl)	$42	$71	$88	$103
Net operating income	**$29**	**$105**	**$335**	**$351**
G&A	($11)	($14)	($22)	($22)
Net derivative impact	$5	($13)	$37	$13
Adjusted EBITDA	**$23**	**$78**	**$350**	**$342**
Capex	($42)	($82)	($120)	($111)
Free cash flow **(including derivatives)**	**($19)**	**($4)**	**$230**	**$231**
Net debt (cash)	**32**	**55**	**(128)**	**(137)**



Free cash flow matrix in USD millions[1-7,*]

Yearly production (bopd) →

Brent USD/bbl ↓

	15,000	17,500	20,000	22,500	25,000
$110	$261	$317	$371	$425	$478
$105	$237	$289	$339	$390	$439
$100	$213	$261	$309	$356	$402
$95	$189	$234	$278	$322	$365
$90	$165	$206	$247	$287	$327
$85	$141	$179	$217	$255	$292
$80	$117	$152	$186	$220	$254
$75	$93	$125	$156	$187	$218
$70	$69	$97	$125	$152	$179

Adj. guidance

Org. guidance

**Assumes a $110 million Capex program run rate G&A range of $3.3 -$4.0/bbl (current G&A/bbl at $3.38/bbl)*
PetroTal can grow over the next 3 years past 25,000 bopd with yearly capex programs of approximately $110 million

Key 2022 Budget Highlights[1-7]

- Average 2022 production of 15,500 bopd which includes 10% total downtime (Q2-Q4 2022)
- Adj. EBITDA at ~ $342 million and assuming no Brazilian diluent blending (Q2 – Q4 2022)
- $111 million of 2022 CAPEX includes:
  - Four new wells on production, plus drilling commencement of a fifth and scheduled rig maintenance ($71 million)
  - New tankage and separators ($10 million)
  - CPF-3 engineering and mechanical work ($15 million)
  - Gathering lines, injection facilities, power plant expansion, erosion control ($13 million)
  - Block 107 permits ($2 million)

Significant storage capacity and offtake options mitigate ONP risk

Block 95 (Bretaña)

- Iquitos route by barge
- Pump station 1 by barge
- To Manaus terminal by barge (barging cost netted into sales price)

Access to:	Storage k bbl	# of days @ 15k bopd	Cuml. # of days @ 15k bopd
Bretaña[1]	90	6.0	6.0
ONP Barges[2]	360	24.0	30.0
Station 1[5]	300	20.0	50.0
Station 5[5]	480	32.0	82.0
Total	**1,230**	**82 days at 15k bopd**	

Access to:	Offtake k bbls p.m.	Equivalent k bopd
Brazil Offtake[3-4]	400 – 500	13.3 – 16.6
Iquitos Market[3]	60	2.0
Total	**280 - 560**	**15.3 – 18.6**

Key Highlight

- If total production is 26,600 bopd and up to 18,600 bopd is being sold to Iquitos and Brazil, PetroTal can still store the remaining production for **up to 56 days** excluding the use of Station 1 and 5 and up to **150 days** including Station 1 and 5 (if economically viable)

Extensive facility investments in place

Significant scalable infrastructure in place

- Investment of >$100 million achieves processing capacity of ~26,000 bopd[1]
- 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 full 2P program with current infrastructure with additional water disposal
- Power generation fuelled by crude oil instead of diesel resulted in +$100 million NPV(10)

Build history from 2018 - 2021

Capacity Stage	Incremental Oil bopd	Incremental Water bwpd[2]
Long-Term Testing Facility	8,000	9,000
Central Processing Facility #1	8,000	41,000
Central Processing Facility #2	8,000 – 10,000	50,000
Total	**Up to 26,000**	**100,000**

Jan 2021

May 2022

See presentation footnotes in appendix

2022 shareholder return strategy

Subject to board approval and economic viability

No refinancing needed

PetroTal

Completed

April 1, 2022

Pay back $20 million in bonds

15,500 bopd

Deliver consistent production through Q4 2022

Q4 2022/2023

Retire remaining $80 million bond
(requires retirement to return capital)

Bond retirement optionality

- Retire bonds as cash flow generation allows
- Move to a robust shareholder capital return program

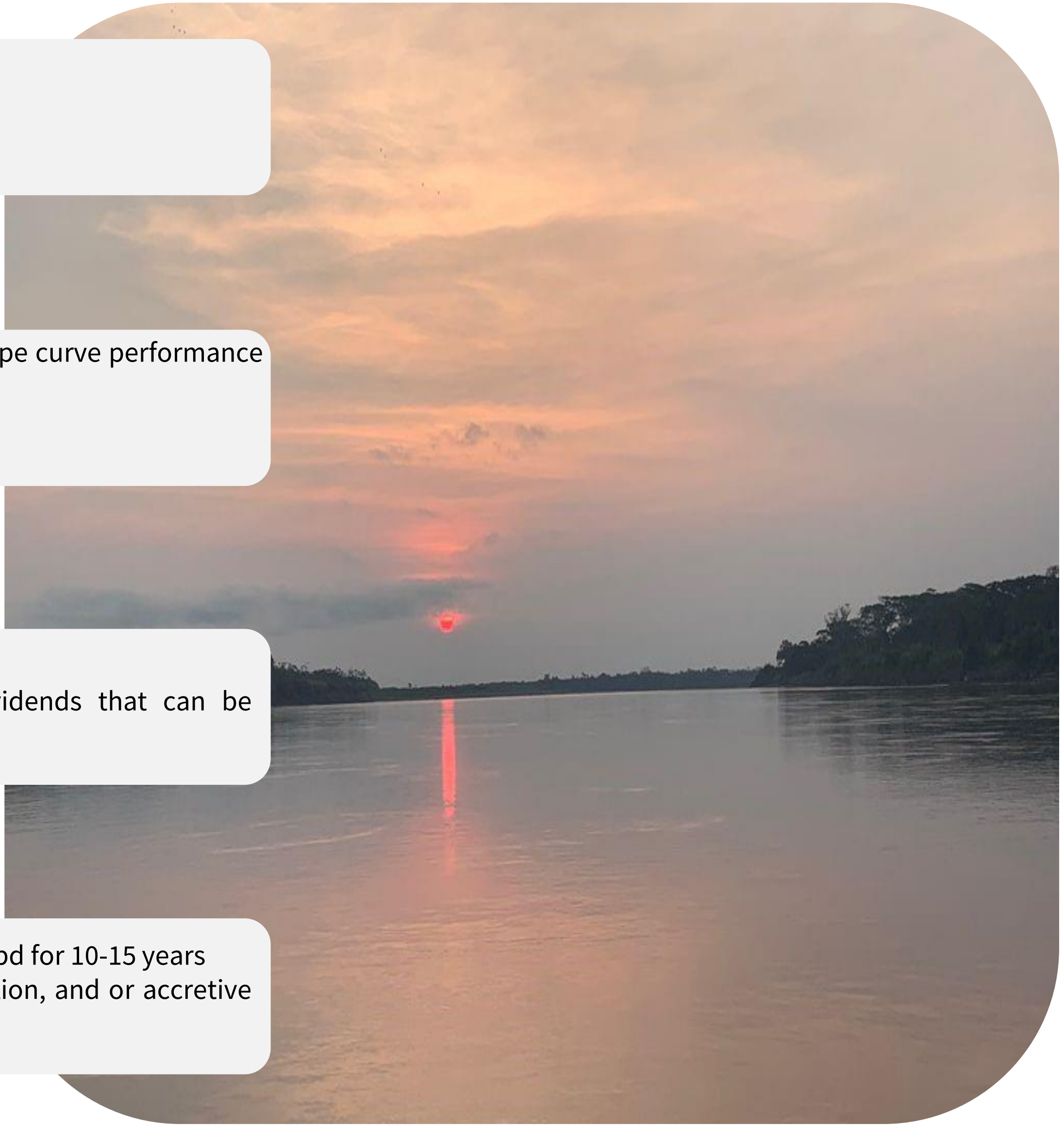
Share buybacks
(subject to exchange rules)

Dividends

Continued Block 95/107 development

Not subject to bond retirement

1-3 year strategic initiatives



Debt free balance sheet

- Management philosophy of being debt free near top of the pricing cycle
- Derisks balance sheet long term
- Maximizes free cash flow[1] to investors at top of pricing cycle
- Allows PetroTal to source debt (if needed) near bottom of pricing cycle

Execution of 2P & 3P development plans in core area

- Management will not grow for the sake of growth. Growth levels driven by type curve performance at a ~4-5 well per year run rate. (no overcapitalization needed)
- Includes derisking route to sale markets and managing social protesting
- Operational focus on processing fluids, drilling wells, disposing of water

Return significant free cash flow to shareholders

- Provided a structured and accretive share buyback program
- Will augment returns to shareholders with quarterly and or special dividends that can be maintained through lower pricing cycle points with lower share count

Extend development life of PetroTal's assets

- Extend drillable development life past five to six years to maintain > 25,000 bopd for 10-15 years
- Accomplished through Bretaña booked location expansion, low-risk exploration, and or accretive M&A that meets investment grade return hurdles and diversifies offtake risk

See presentation footnotes in appendix

3-10 year strategic initiatives

Achieve Bretaña production plateau

- Done via consistently drilling 4-5 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

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[1] flow to shareholders

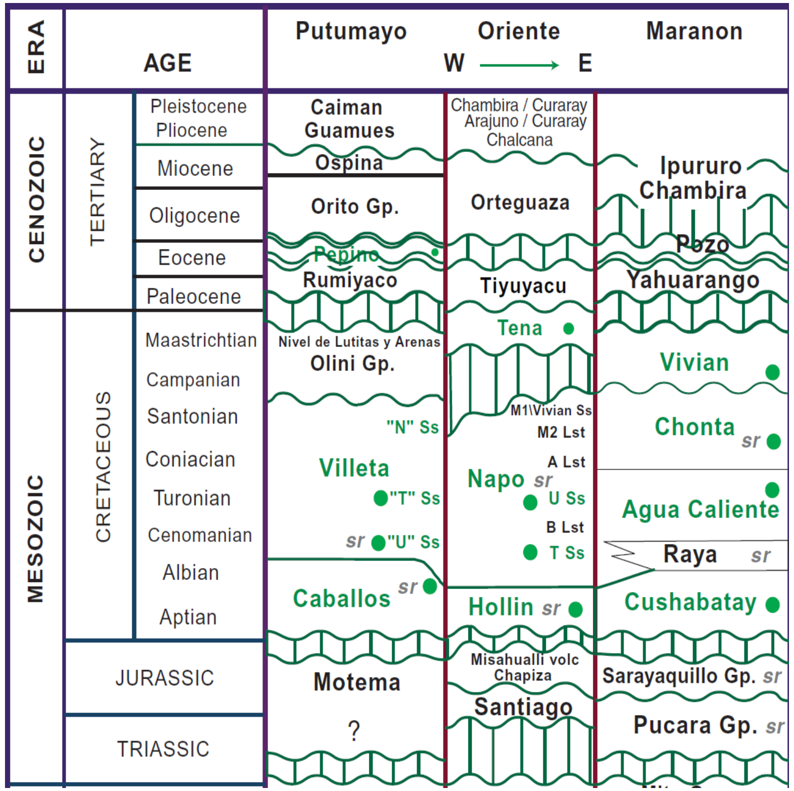
- Significant return of capital to shareholders via buybacks and or dividends

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

See presentation footnotes in appendix

Bretaña regional geology

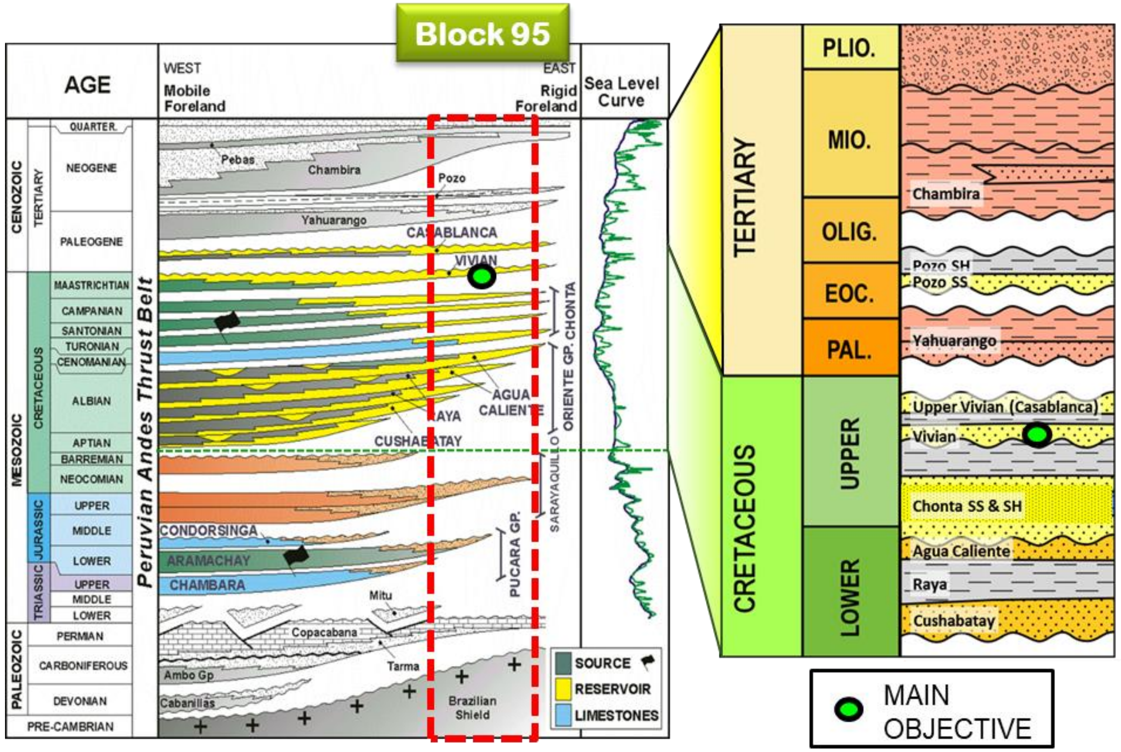


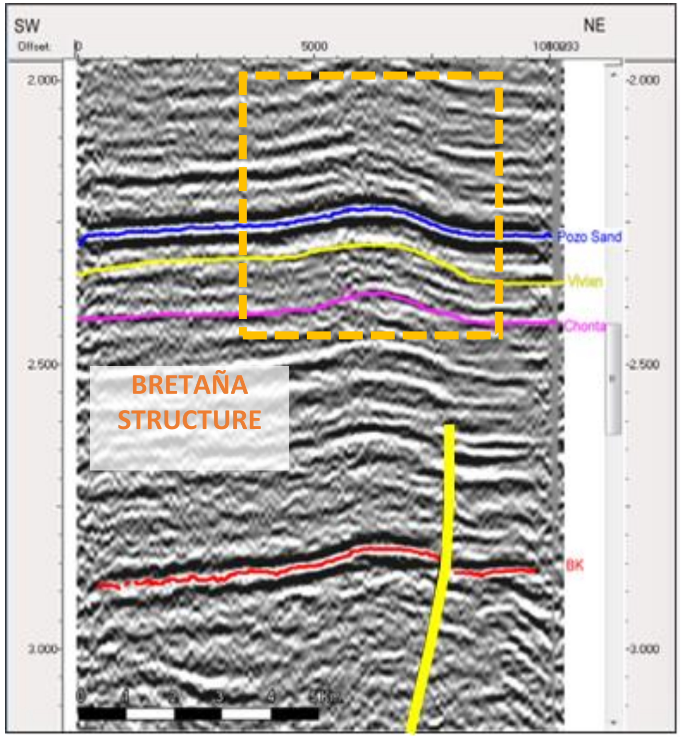
Technical specs	Measure
Pressure	3,942 PSI
Temp	214 ^{0}F
API	18.6
GOR	25 scf/bbl
Pb	320 psia
Oil FVF	1.056
µ o	23.6
Density	0.895 g/cc
Perm	2,000 md
Porosity	22.6 %
Saturation	38.0 Sw
Thickness	59 feet
Field size	15,028 acres

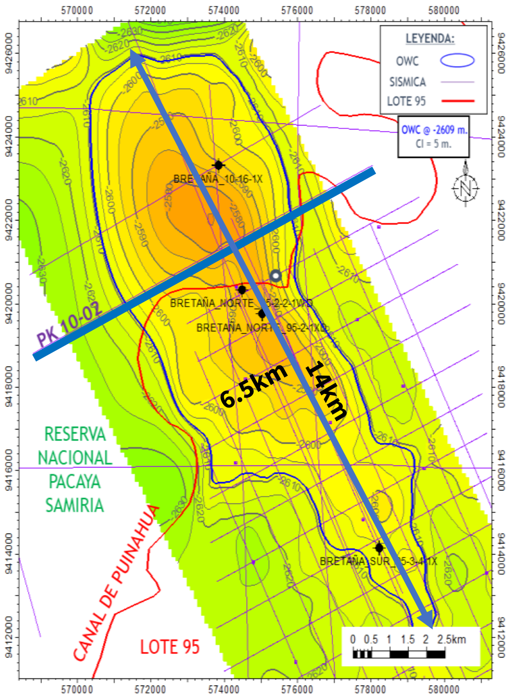
Key highlights

- The Marañon basin is the southern extension of the larger foreland basin that covers the Putumayo (Colombia) and Oriente (Ecuador). The Marañon is the least explored
- The Marañon basin has a sediment pile greater than 6,000 m in the depocenter. The oldest rocks reported are of Devonian age, within grabens
- The Bretaña field is a subtle structure located on the south-eastern margin of the basin that is filled to spill-point
- Although the Marañon basin has two proven petroleum systems, only one is present in Block 95 (Cretaceous Vivian sandstones charged by the Jurassic Pucará source rock)

Bretaña structural trap



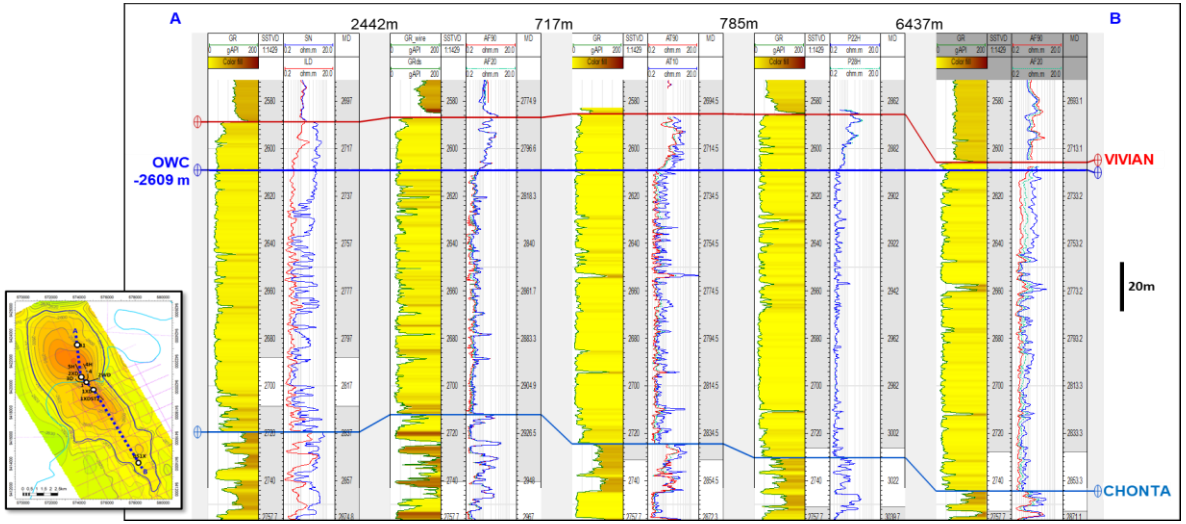


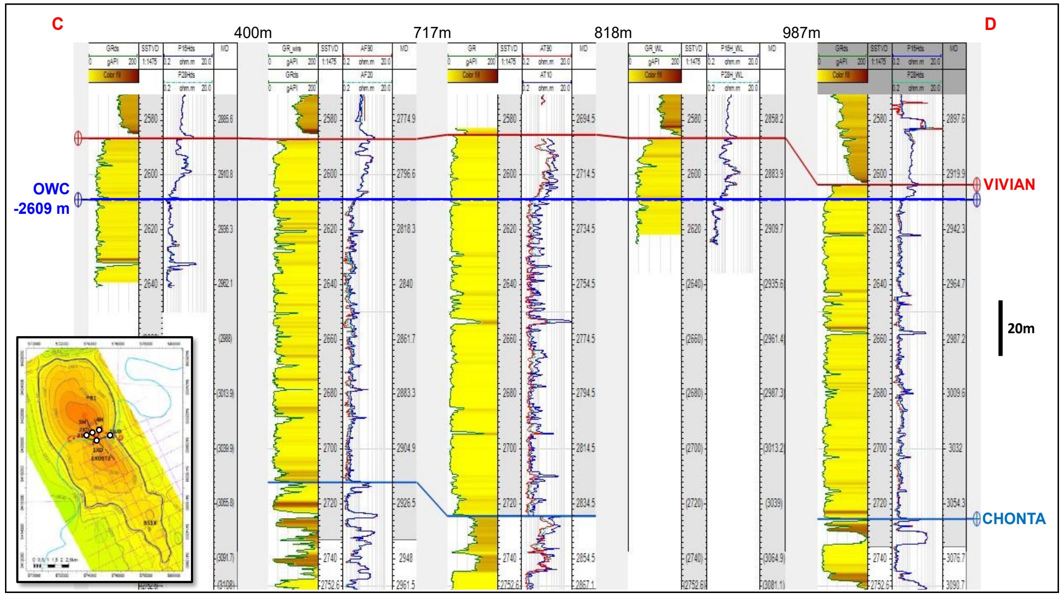


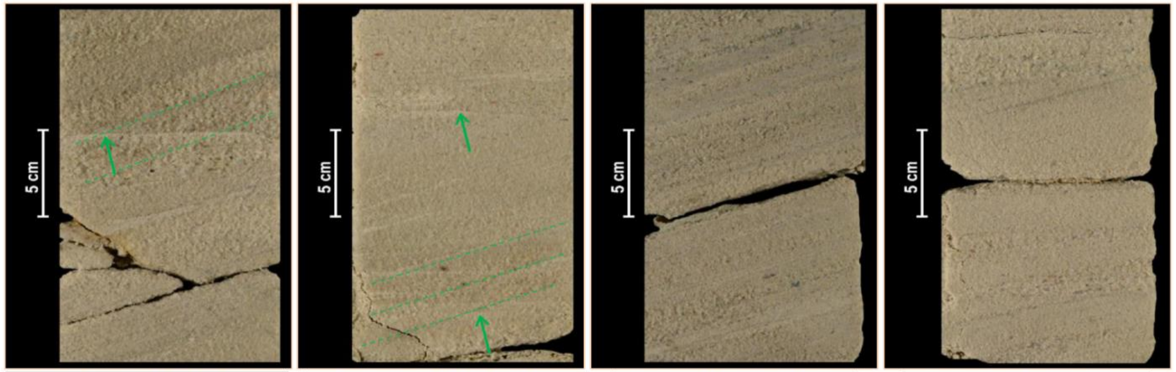
Key highlights

- The trap is induced by an inverted basement fault that does not reach the Vivian Fm. and is defined by subtle low relief, 4 way closure, and NW-SE elongated structure
- Part of the field spans into the Pacaya-Samiria National Reserve

Bretaña geology and petrophysics







A.- Depth: 2900.80/2901.00 m.
Nearest sample 3-8-20 P: 2901.02 m.
Ø= 30.96%, K= 9585.64 mD

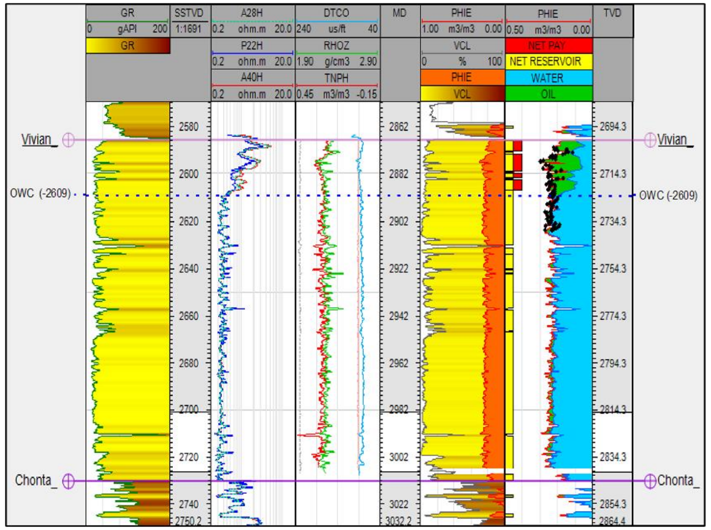
B.- Depth: 2902.88/2903.08 m.
Nearest sample 3-10-26 P: 2902.85 m.
Ø= 26.71%, K= 6105.82 mD

C.- Depth: 2903.60/2903.80 m.
Sample 3-11-31 P: 2903.70 m.
Ø= 26.37%, K= 6553.69 mD

D.- Depth: 2904.98/2905.18 m.
Sample 3-12-37: 2905.10 m.
Ø= 27.06%, K= 6487.75 mD

Planar cross-bedded medium grained quartz sandstones

- Vivian Fm: Fluvial deposits consisting mainly of a channel complex in a braided river system, with little or no evidence of plain deposits. The channels represent fining upward systems
- Core deposits show irreducible water saturation is lower than thought = **more movable oil**



RESERVOIR ZONE:
- GROSS = 144 m
- NET RESERVOIR = 135 m
- Phie (avg) = 23 %
- Vclay (avg) = 7 %
- K core (avg) = 1000 mD.

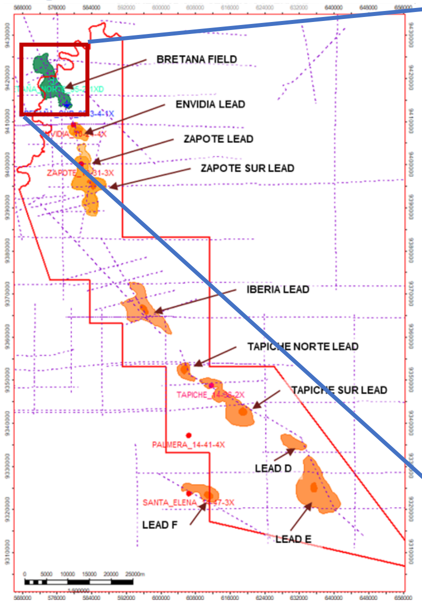
PAY ZONE:
- NET PAY = 18 m
- Phie (avg) = 24 %
- Vclay (avg) = 7 %
- Sw (avg) = 30 %
- OWC @ -2609 m.

CUTOFF:
Phie ≥ 12 %
Vclay ≤ 30 %
Sw ≤ 60 %

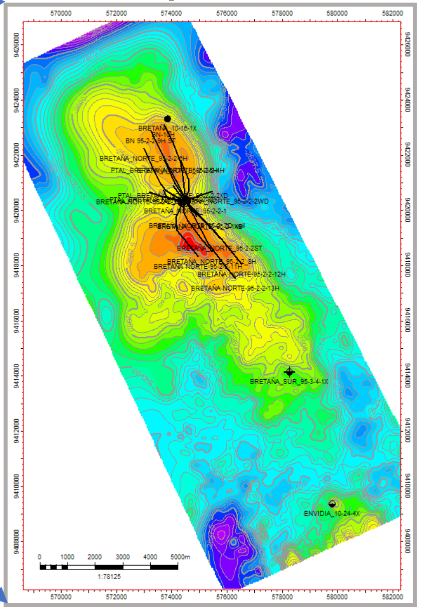
- Very good sandstone reservoir quality with local heterogeneities.
- OWC based on MDT and Log Analysis: -2,609 mTVDss.

3D geological model

1 Block 95



2 Bretaña Field Top of Vivian



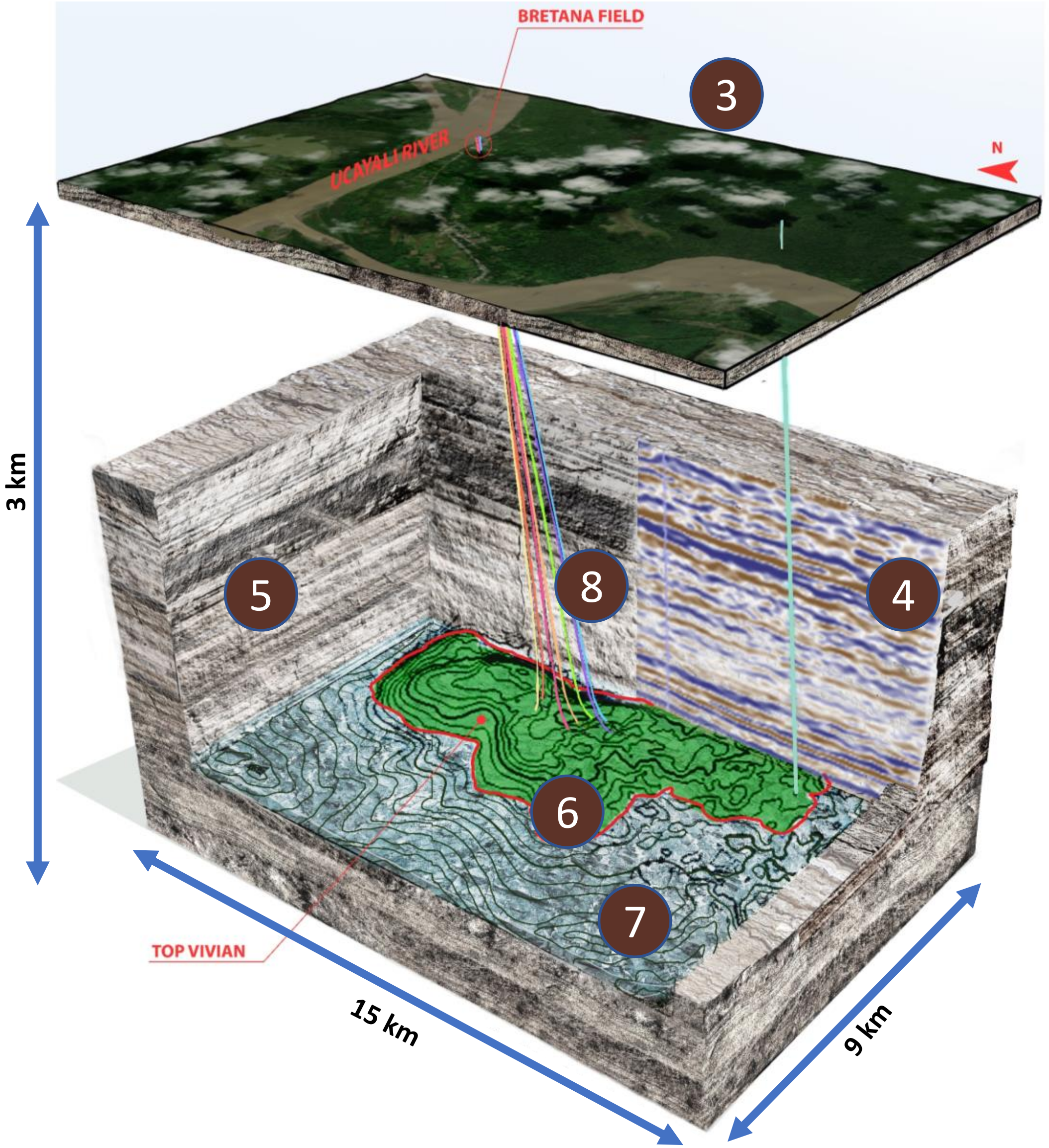
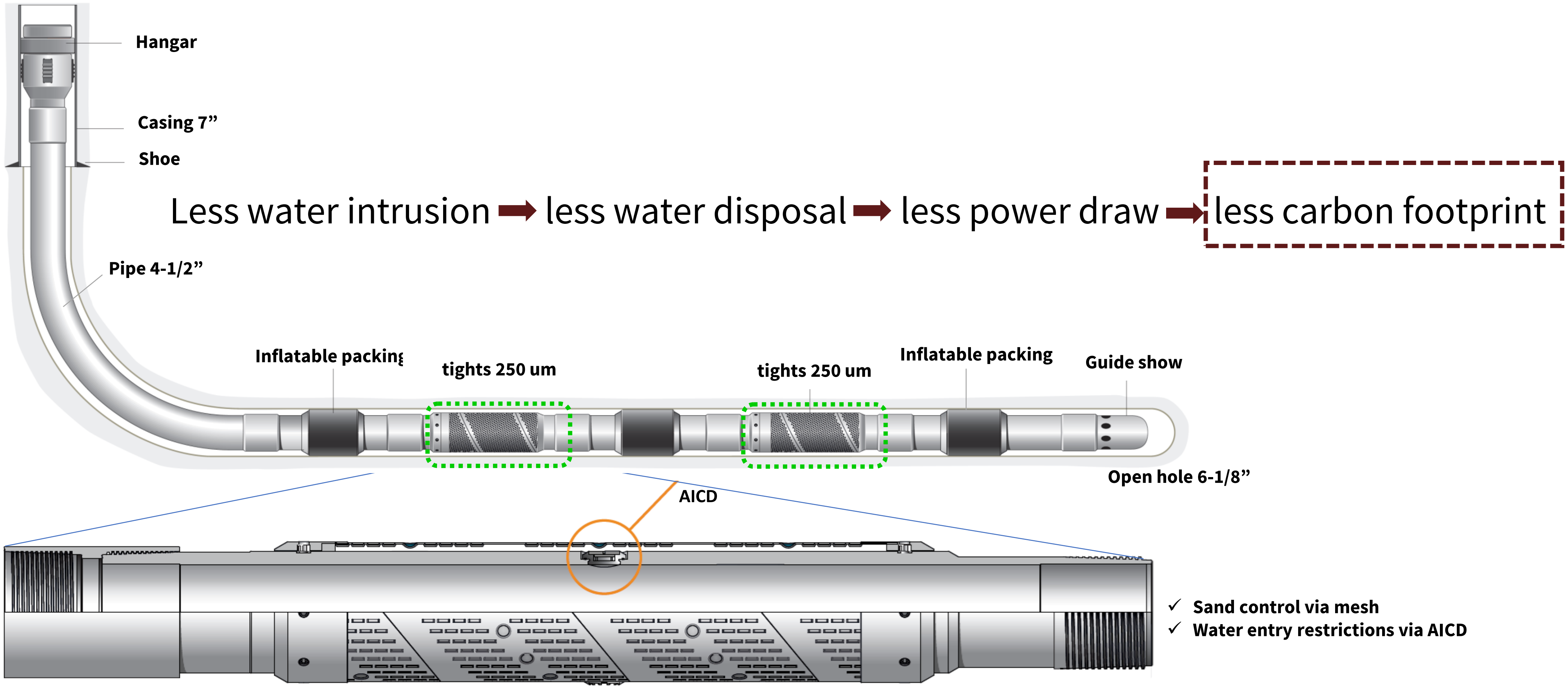


Image references

1) Block 95 boundaries & prospective resources
2) Current structural interpretation of Bretaña field
3) Intersection with surface topography Ucayali River (puinahua channel)
4) Inline of sseudo-3D seismic
5) Lithological 3D cross-section
6) Oil filled structure (green shade)
7) Top of vivian structural surface (blue shade)
8) Bretaña field well trajectories

Completion description



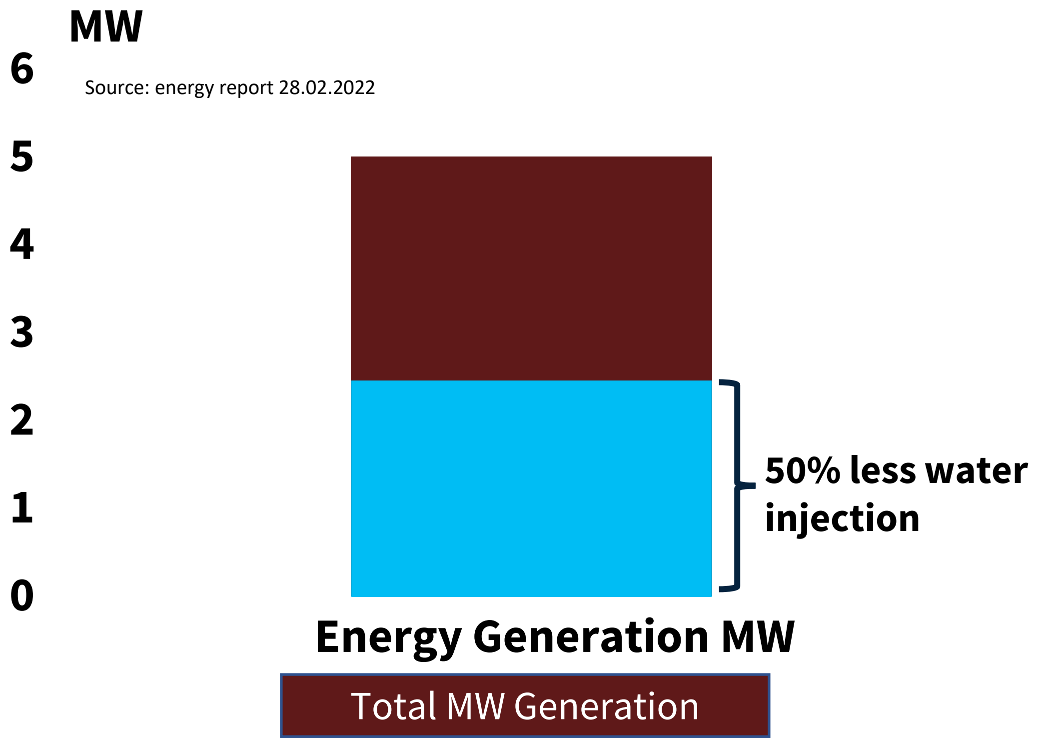
- ✓ **Sand control via mesh**
- ✓ **Water entry restrictions via AICD**

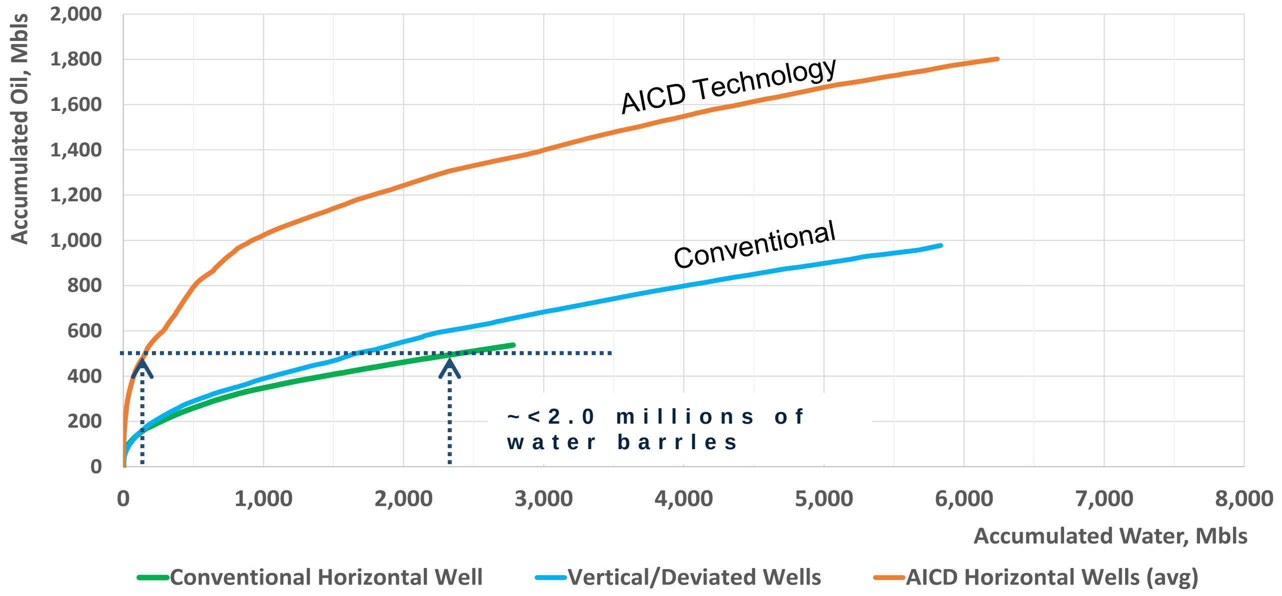
Key highlights

- The implementation of the AICD technology occurs through the installation of a set of valves throughout the productive horizontal zone of the well and that, through a physical principle of pressure change, autonomously manages to restrict the entry of water but allow oil production. The AICD valves are inside the screens installed to filter the sand that the well may produce

Technology application to reduce emissions

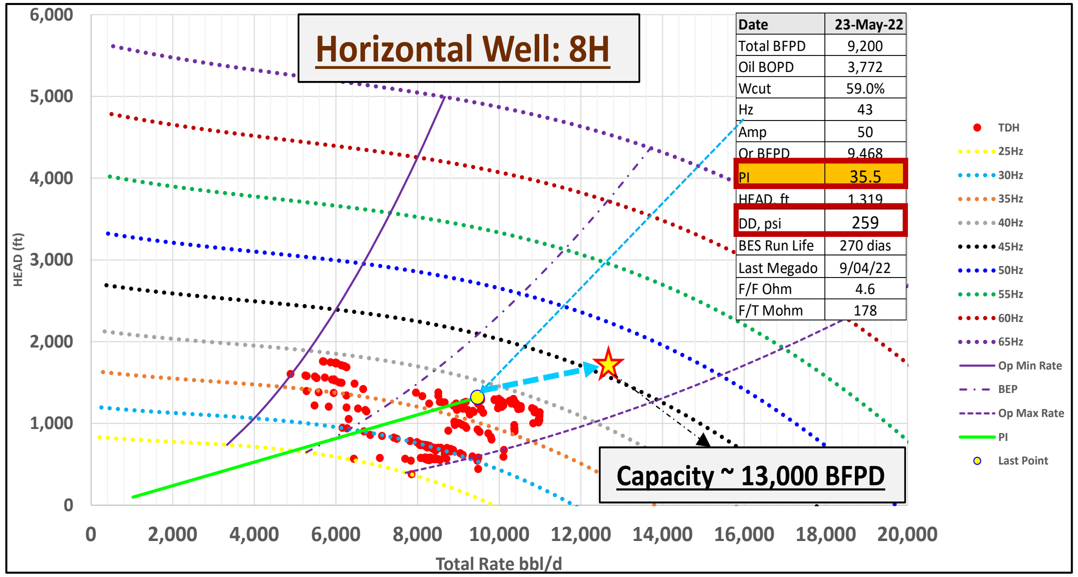
Significant reduction in water production of up to 2.0 MMbls H2O/well with a related reduction in energy use and tCO2e emissions

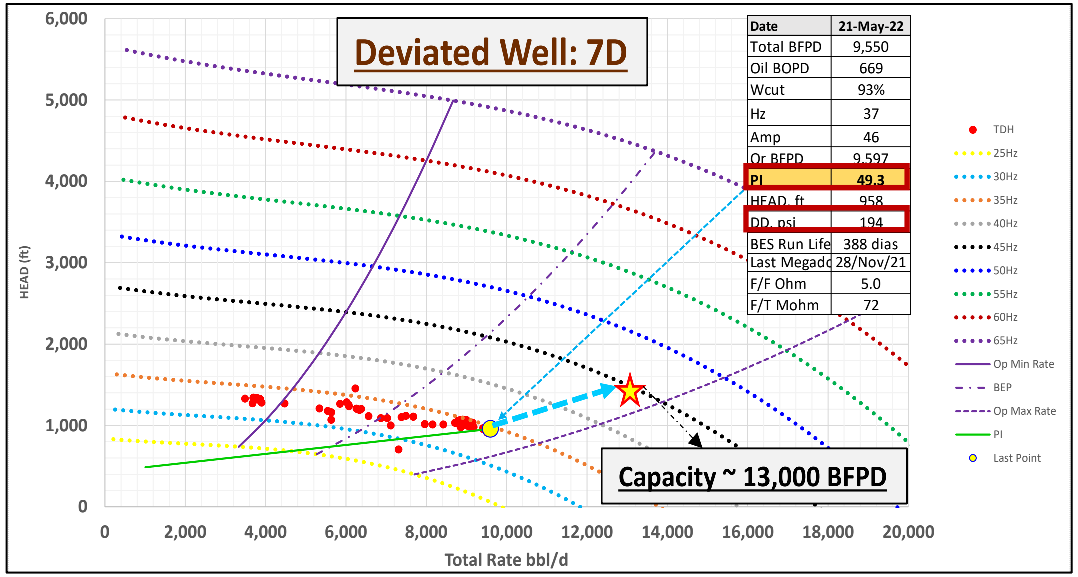




~ Injection of **1,000 bls** of water use **3.5 MWh** <> **2.2 Bls oil**
2.0 MMbls have consumed **7.0 GWh** <> **4,400 Bls oil/well**

Building a factory to process fluids





Building a factory to process fluids is required because Bretaña will eventually produce crude oil with large water cuts

With 22 wells producing an average 10,000 bfpd per well, Bretaña will process 220,000 bfpd:

- At a 10% oil cut, this is equivalent to 22,000 bopd
- At a 5% oil cut, this is equivalent to 11,000 bopd
- At a 3% oil cut, this is equivalent to 6,600 bopd

The above is possible due to:

- Bretaña's excellent well productivity
- Efficient use of AICD valves in the horizontal wells to optimize oil and water production
- Optimum electro-submersible pump ("ESP") performance that allow us to maximize overall fluid production

The data to date shows that we can outperform due to:

- Well's high productivity index (PI > 30 bfpd/psi)
- Low pressure draw down (DD < 300 psi) that delays water channeling
- Observed draw down is less than 10% of reservoir pressure

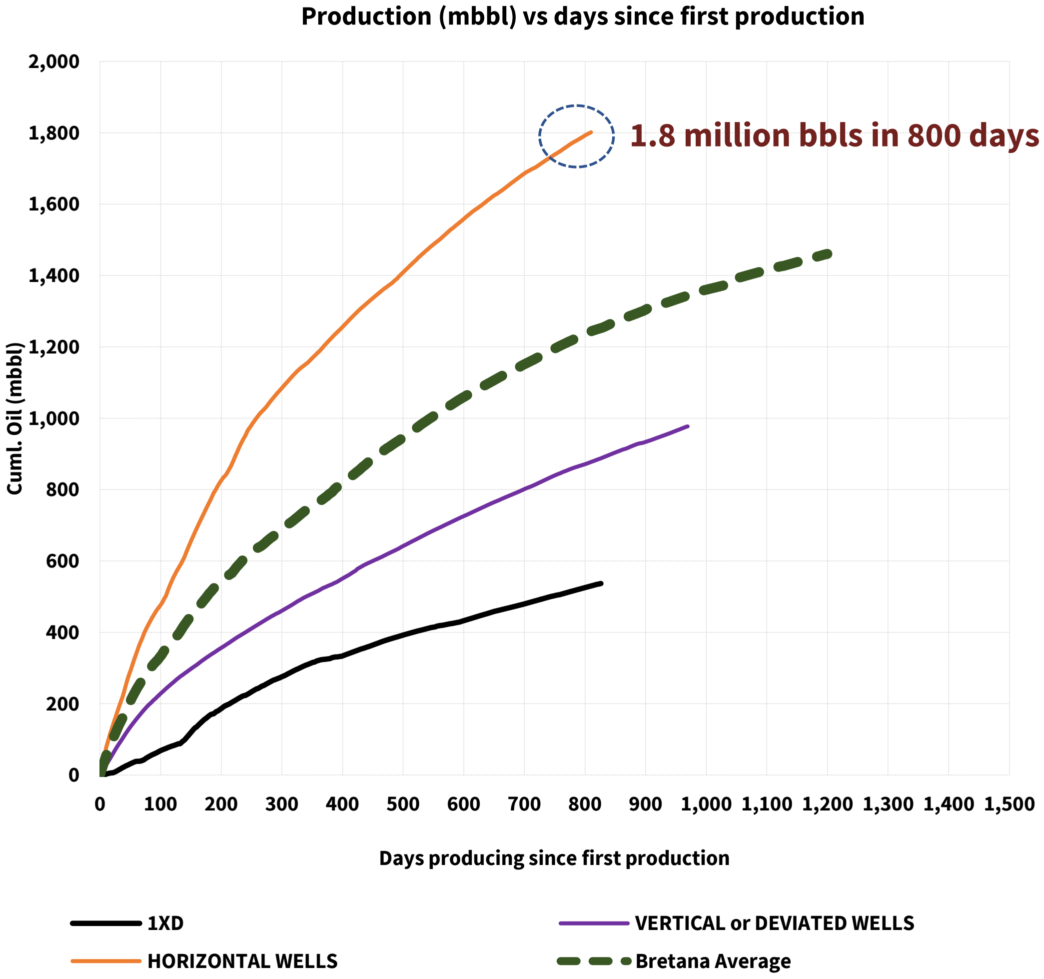
The ESPs are:

- Working at low frequencies due to the wells' high PI's and motor loads of less than 50%
- Operating under optimum conditions according to the respective pump performance curves
- Expected to exceed 3 years of run life
- Able to lift 13,000 BFPD, as shown in the graphs to the left, either from horizontal or deviated wells

Bretaña could eventually lift 286,000 bfpd in the 2P case, and 377,000 bfpd; which at 10% oil cuts would produce 28,600 bopd and 37,700 bopd, respectively

Well Performance

Cumulative oil profiles[1]



Key type curve economic indicators[2, A-F]

	Low	Mid	High	PetroTal Hz wells (ave)
Technical parameters				
EUR mmbbls	2.8	3.1	3.8	**4 – 4.5 (extrapolated)**
Recovery Factor	12%	16%	20%	**21%-26%**
Capex/well ($ millions)	$12	$12	$12	**$12**
NPV (10%) ($ millions)				
$70/bbl Brent	$57	$61	$68	**$80**
$75/bbl Brent	$67	$71	$79	**$95**
$80/bbl Brent	$77	$82	$91	**$110**
IRR	350% - 400%	400% - 450%	450% - 500%	**500% -550%**
Payback (months)				
$70/bbl Brent	2.5	2.5	2.4	**<3.0**
$75/bbl Brent	2.2	2.1	2.1	**<2.0**
$80/bbl Brent	2.0	2.0	2.0	**<1.0**

Economic table notes:

A). All dollar figures are in USD millions

B). Payback is estimated in months

C). NPV uses a 10% discount rate

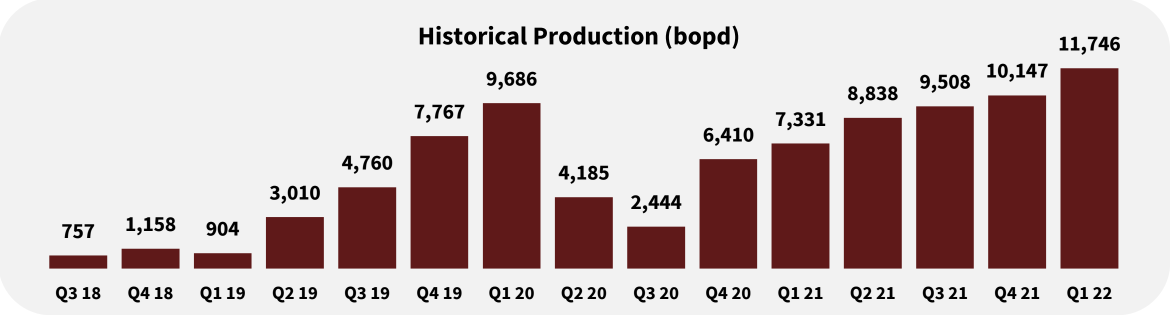
D). NPV, IRR, and payback calculated using $35/bbl, $40/bbl, and $45/bbl netbacks and represent $70/bbl, $75/bbl, and $80/bbl Brent pricing

E). PetroTal currently models, for internal purposes, the low, mid, and high cases based on internal technical assessments for each well

F). PetroTal horizontal well type curve created using 1.5 million barrels produced over the first two years and declined at approximately 20% per year thereafter

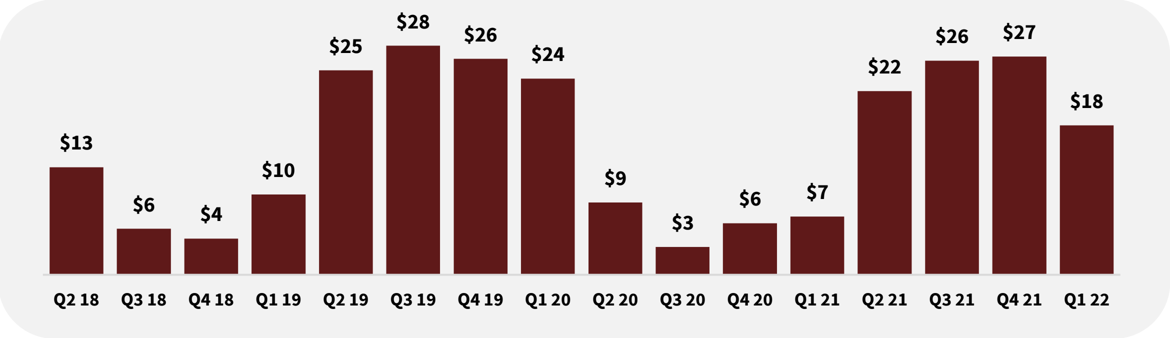
Delivered financial performance to date

Historical production (bopd)



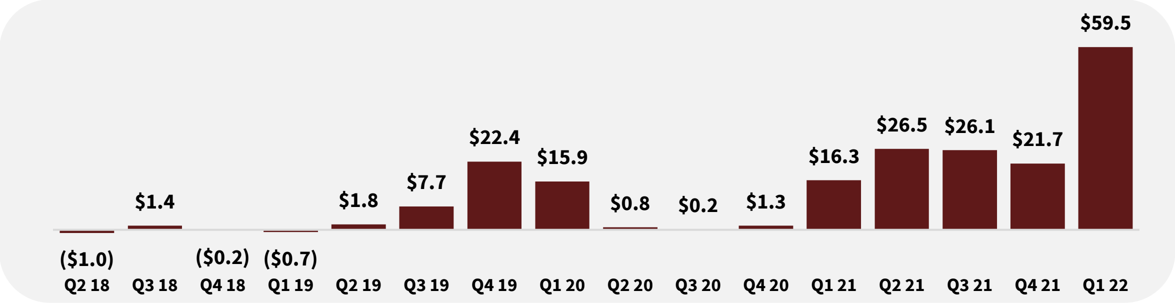
- 7 million bbls produced in 3.5 years
- 6 straight quarters of production growth
- Record daily production of ~21,000 bopd reached in Feb 2022

Historical investment in asset (USD millions)



- >$250 million in Capex spent since inception to generate a 20,000 bopd run rate production level
- Market asset value of 20,000 bopd would be > $0.75 billion (NPV10)
- Low full cycle capital intensity since inception of < $10,000 per flowing bbl
- Forward looking capex weighted to drilling
- Best in class well economics (payouts < 30 days)

Historical EBITDA[1] (USD millions)



- ~$200 million in cumulative EBITDA[1] generated since 2018
- Top tier EBITDA/bbl metrics for a heavy to medium oil producer peer group
- Operating leverage that allows free cash flow to scale with Brent and production increases

See presentation footnotes in appendix

Financial summary

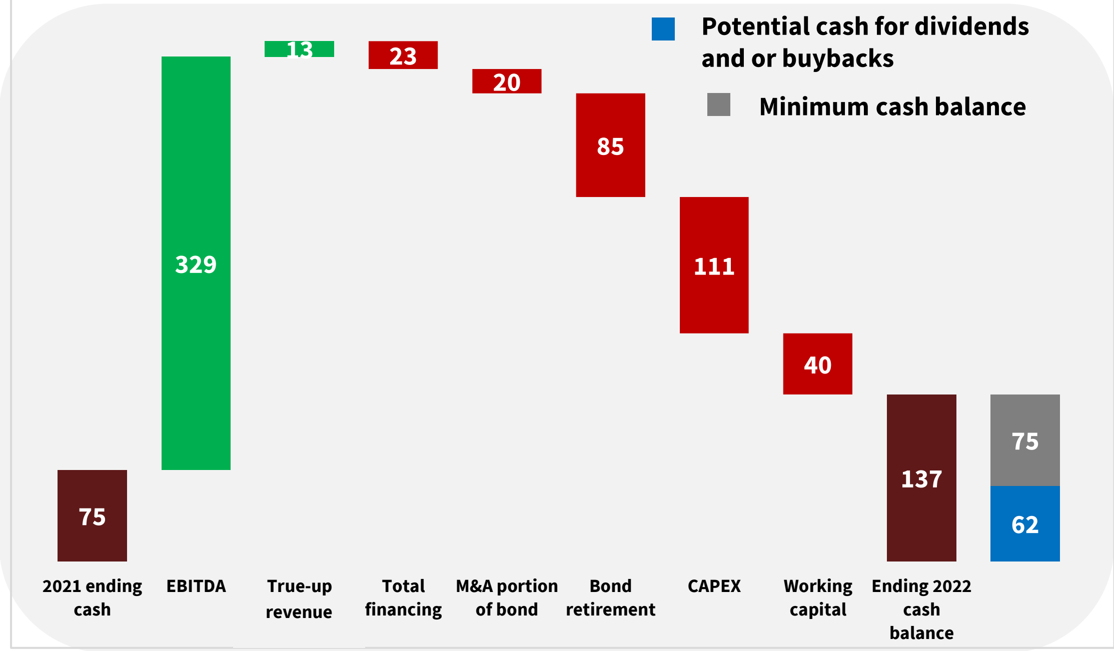
Balance sheet strength (USD millions)[1-4]

Key financial figures	2018	2019	2020	2021	Q1 2022	2022 (estimated)
Cash	**26.3**	**21.1**	**9.1**	**74.5**	**52.9**	**130.0-140.0**
Total receivables	8.6	24.0	15.6	5.4	57.6	10.0
Derivative liability (asset)	-	0.4	4.0	(36.7)	(64.1)	(40.0)
Short and long term debt	-	55.0	52.6	171.8	165.5	50.0
Adjusted net debt (net cash)	**(27.4)**	**10.4**	**31.9**	**55.3**	**(9.2)**	**(137.0)**
Decommissioning	11.1	17.6	21.1	22.2	18.9	30.0
Equity	77.5	121.1	137.2	204.3	270.8	200.0
NOI	**5.1**	**41.9**	**28.9**	**104.9**	**64.2**	**351.0**
G&A	(6.1)	(10.7)	(10.7)	(14.3)	(4.7)	(22.0)
EBITDA (NOI – G&A)	**(1.0)**	**31.2**	**18.2**	**90.6**	**59.5**	**329.0**
Net debt / EBITDA	**N/A**	**0.3x**	**1.8x**	**0.61x**	**N/A**	**N/A**

Key highlights

- Currently net debt free
- Significant cash build by 2022 year end assuming ~$102/bbl contracted Brent
- History of strategically using equity and debt and avoiding overcapitalization
- Top tier heavy oil EBITDA netbacks (~$60/bbl assuming $102/bbl contracted Brent)
- Low decommissioning liability from low well count and small field footprint
- Ability to flex accounts payable and use vendor financing

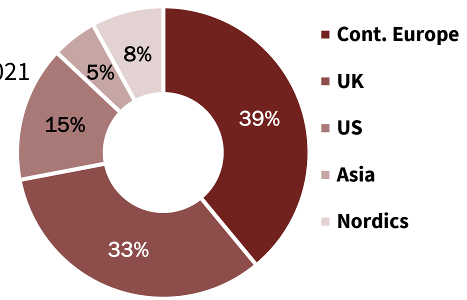
2022 cash flow waterfall (USD millions)[1-4]



Bond highlights

- Only material debt of Company
- $100 million bond issuance closed in February 2021
- 12% semi annual coupon
- Amortization spread out over three years
- Covenant light (shareholder returns restricted)

Bond geography



Netback contribution by sales route

EBITDA/bbl sensitivity (USD/bbl)[1-5]

Netback Summary $/bbl	Brazil $/bbl	Iquitos $/bbl	Saramuro $/bbl	2022 $/bbl
Sales (bopd)	13,300	1,300	1,200	15,500
Contracted Brent	**$102.0**	**$105.0**	**$99.0**	**$102.0**
Differential	($5.0)[3]	($20.0)	($3.5)	($5.1)
Transportation	($15.0)	-	($14.5)	($14.9)
Royalties	($7.4)	($7.7)	($7.3)	($7.5)
Diluent in sales	-	$3.0	$3.0	$0.5
Net Revenue	**$74.6**	**$80.3**	**$76.7**	**$75.0**
Lifting	($7.5)	($7.5)	($7.5)	($7.5)
Diluent Cost	-	($6.4)	($6.4)	($1.0)
Barging Service	-	($2.5)	($3.0)	($1.7)
Barging Diesel	-	($1.0)	($1.5)	($0.8)
Barging Storage	-	($0.5)	($1.0)	($0.5)
Netback	**$67.1**	**$62.4**	**$57.3**	**$63.5**
G&A	($4.0)	($4.0)	($4.0)	($4.0)
EBITDA	**$63.1**	**$58.4**	**$53.3**	**$59.5**

Key Highlights

- Diluent not required for Brazil shipments generating up to $10 million in additional NOI
- ~60% EBITDA margins prior to true up revenue at just over $100/bbl Brent
- 80% of every dollar increase in Brent falling to netback
- Smaller Brazil shipment sizes shown for illustration purposes
- Table does not include one time inventory allocations into OPEX which are included in the latest 2022 EBITDA guidance of $329 million

ONP derivative 2022 income

3.1 million barrels in the ONP estimated to reach Bayover starting Nov 2022 to Nov 2024[6]

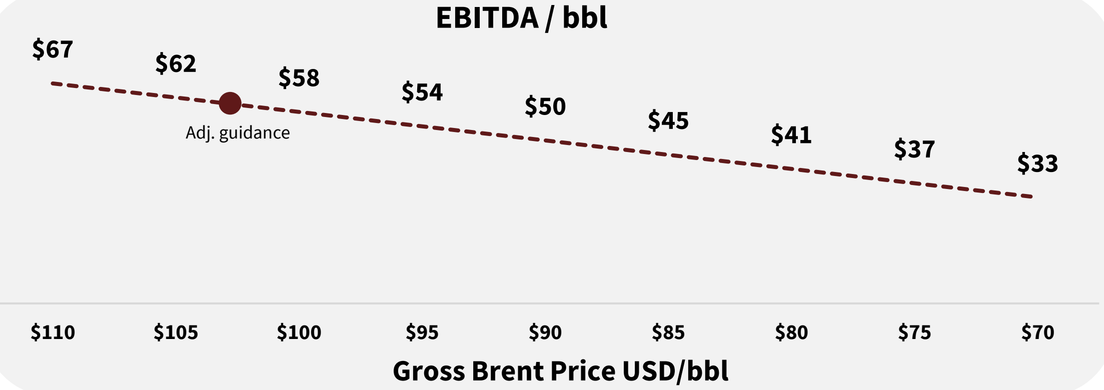
At Dec 31, 2021 → **37 million gain in 2022**

2022 Budget$_0$ → **37 million gain in 2022 + $5.4/bbl (18,250 bopd)**

2022 Budget$_1$ → **13 million net gain in 2022 + $2.5/bbl (15,500 bopd)**

~$40-$45 million of true up revenue now being realized in 2023

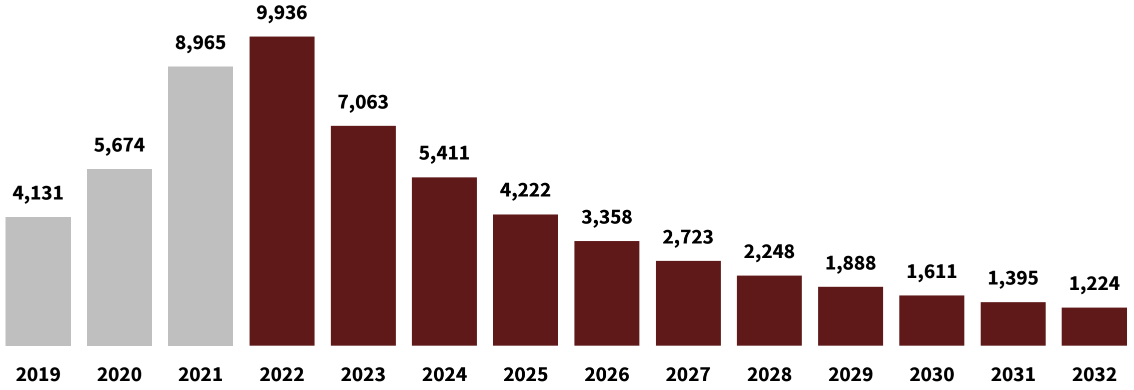
EBITDA/bbl sensitivity (USD/bbl)(no true up)



See presentation footnotes in appendix

A blowdown analysis

Blowdown development production profile (USD millions) (bopd)[1-5]



	2019	2020	2021	2022	2023	2024	2025	2026	Total 2022 - 2026	Total 2022 - 2031
Brent	$64	$42	$71	$102	$93	$83	$75	$70	$85	$77
Capex[3]	89	42	82	40	0	0	0	0	40	40
Well count	6	7	10	11	11	11	11	11	11	11
EBITDA[2]	31	18	91	210	109	67	40	28	454	504
Free cash[2]	(58)	(24)	8	170	109	67	40	28	414	465

5 Yr profile (2022 – 2026)

10 Yr profile (2022 – 2031)

Key Highlights

- Past investments in material infrastructure are overbuilt and unscaled
- Base declines taking the asset to sub 5,000 bopd by 2025
- Restarting development in 2025 or 2026 to reach 20,000 bopd levels would limit returns to shareholders

Highlights[1-5]

Blowdown NPV 10 - $430

5 Yr free cash flow - $414

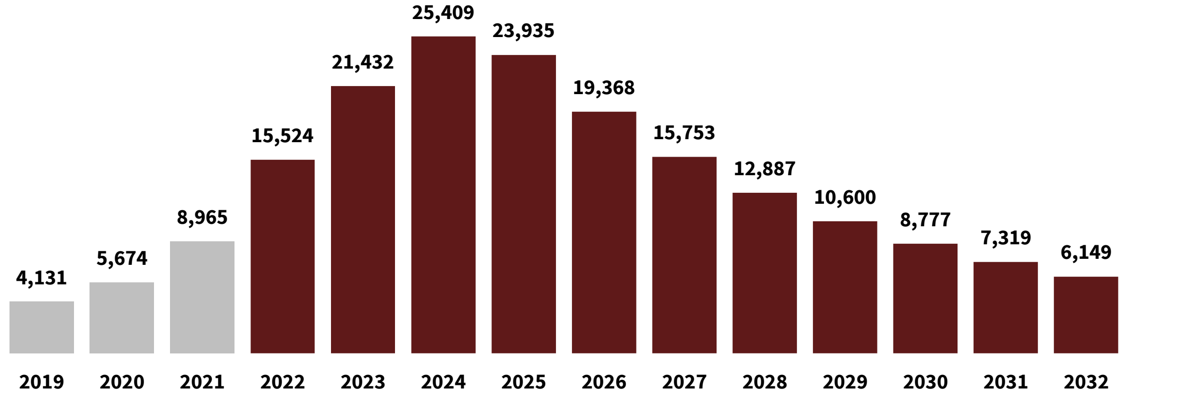
5 Yr other cash burdens – ($70)

5 Yr shareholder return potential = $344

Reserves – 19.6 mmbbl
Includes well 10H

2P development analysis

Internal 2P development production profile for optimal returns (USD millions) (bopd)[1-5]



	2019	2020	2021	2022	2023	2024	2025	2026	Total 2022 - 2026	Total 2022 - 2031
Brent	$64	$42	$71	$102	$93	$83	$75	$70	$85	$77
Capex[3]	89	42	82	111	87	98	18	0	314	314
Well count	6	7	10	14	17	21	22	22	22	22
EBITDA[2]	31	18	91	329	383	384	313	244	1,653	2,328
Free cash[2]	(58)	(24)	8	219	296	285	295	244	1,340	2,015

5 Yr profile (2022 – 2026)

10 Yr profile (2022 – 2031)

Key Highlights

- Optimal development plan to scale past infrastructure investments
- Exciting shareholder return potential of over $920 million through next 5 years after all other cash burdens
- Can drill one well per quarter through 2024 with marginal infrastructure investment

Highlights[1-5]

2P Total NPV 10 - $1,239

5 Yr free cash flow - $1,340

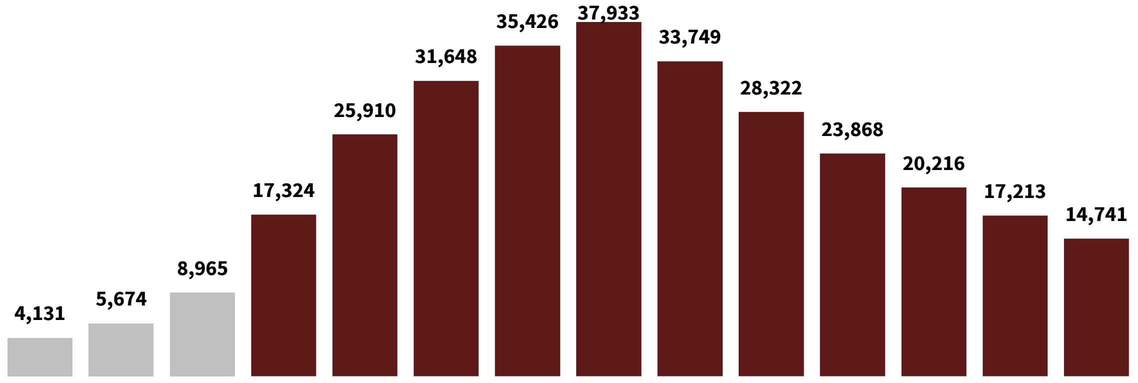
5 Yr other cash burdens – ($420)

5 Yr shareholder return potential = $920

Reserves – 77.9 mmbbl

3P development analysis

Internal 3P development production profile for maximum returns (USD millions) (bopd)[1-5]



	2019	2020	2021	2022	2023	2024	2025	2026	Total 2022 - 2026	Total 2022 - 2031
Brent	$64	$42	$71	$102	$93	$83	$75	$70	$85	$77
Capex[3]	89	42	82	111	107	108	104	82	512	542
Well count	6	7	10	14	17	21	25	29	29	29
EBITDA[2]	31	18	91	385	464	482	459	474	2,264	3,822
Free cash[2]	(58)	(24)	8	274	356	373	355	392	1,751	3,280

5 Yr profile (2022 – 2026)

10 Yr profile (2022 – 2031)

Key Highlights

- Largest and longest development plan requires > ~$200 million of additional infrastructure
- Largest shareholder return potential of over $1.1 billion through next 5 years after all other cash burdens
- Can drill one well per quarter through 2026 and potentially achieve 38,000 bopd

Highlights[1-5]

NPV 10 - $1,858

5 Yr free cash flow - $1,751

5 Yr other cash burdens – ($650)

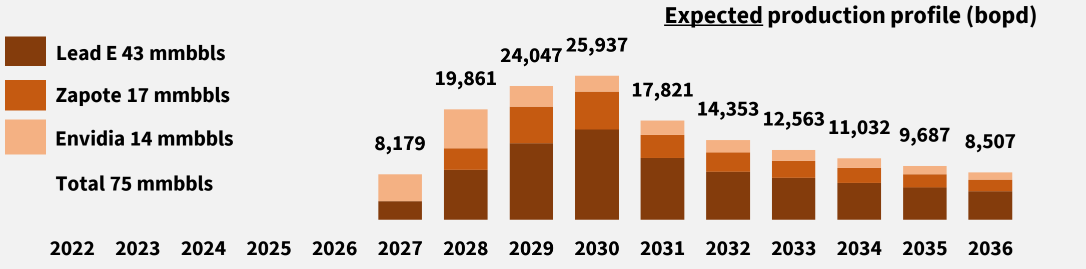
5 Yr shareholder return potential = $1,101

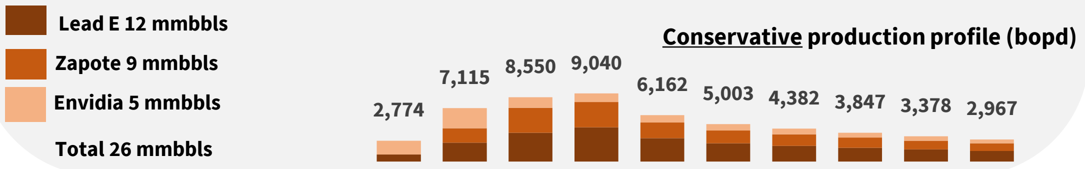
Reserves – 147.0 mmbbl

Situation analysis – Block 95 extension

Opportunity to create another Bretaña[1-5]

- Technical estimate of >25 locations @ $10-$14 million per drill using 3.0 mmbbls EUR per well in expected case and 1.0 mmbbls EUR in conservative case
- Total infrastructure spending of $360 million over length of projects and includes seismic and first surface locations
- Lead D and Iberia not modeled at this this time
- **100% WI view**
- **75 mmbbls recovered (expected case)**
- **First production – late 2027**

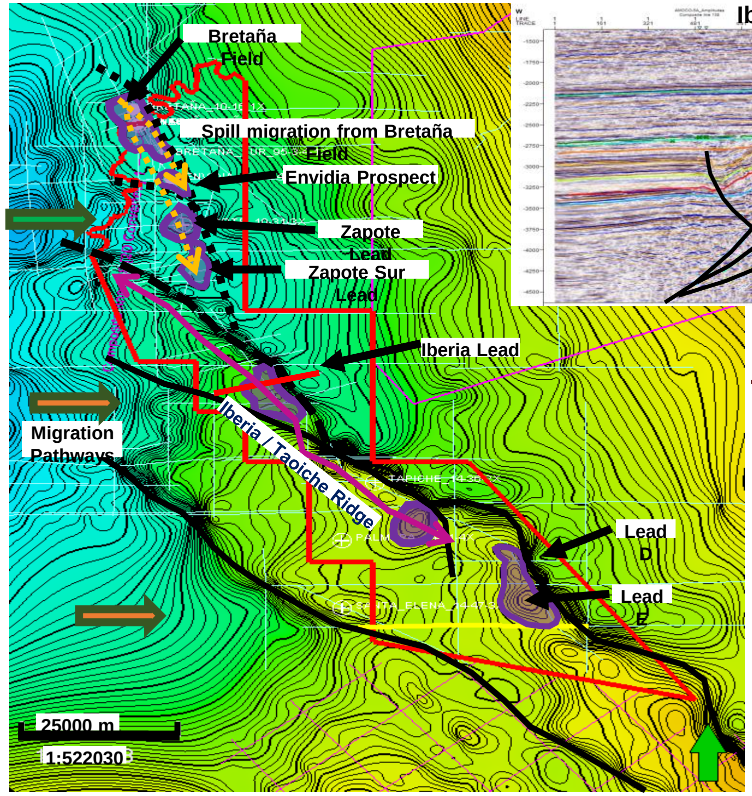


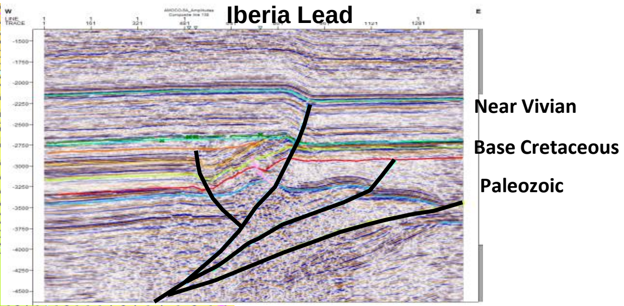


Performance[1-5] (expected case)

- NPV 10 - $530
- Free cash flow - $1,900
- Project break even – 3 YRs
- Net Project Capex - $630
- Net well count - 25
- PIR – 2.5x
- Cash from Bretaña - $140[2]
- Return of capital life – 15 Yrs

Time structure map (top of Vivian)





Unrisked prospects[1]	Best estimate (mmbbl)	Mean (mmbbl)
Envidia	5.3	5.6
Unrisked leads[1]	**Best estimate (mmbbl)**	**Mean (mmbbl)**
Zapote	2.5	3.3
Zapote Sur	6.4	13.3
Iberia	10.8	24.7
Lead D	7.9	22.8
Lead E	12.1	45.0
Total	45.0	114.7

Highlights

- Several prospects and leads identified, on trend with Bretaña Field.
- NW-SE Structural trend positioned to receive hydrocarbon charge from the west, spill migration from the Bretaña field, which is filled to spill point and potentially from deeper Paleozoic source rocks below the trend.
- Leads are very similar to Bretaña and other producing fields in the basin which follow the same geological pattern observed in the block.
- Acquisition of 2D seismic will materially reduce the risk of these features
- An estimated $25 million seismic program has been designed to upgrade leads to drillable prospects and is expected to commence in mid 2023 based on permitting approvals, which the company is now pursuing
- Mean prospective resources >2x current 2P reserves on Bretaña Field[2]

Osheki-Kametza technical overview

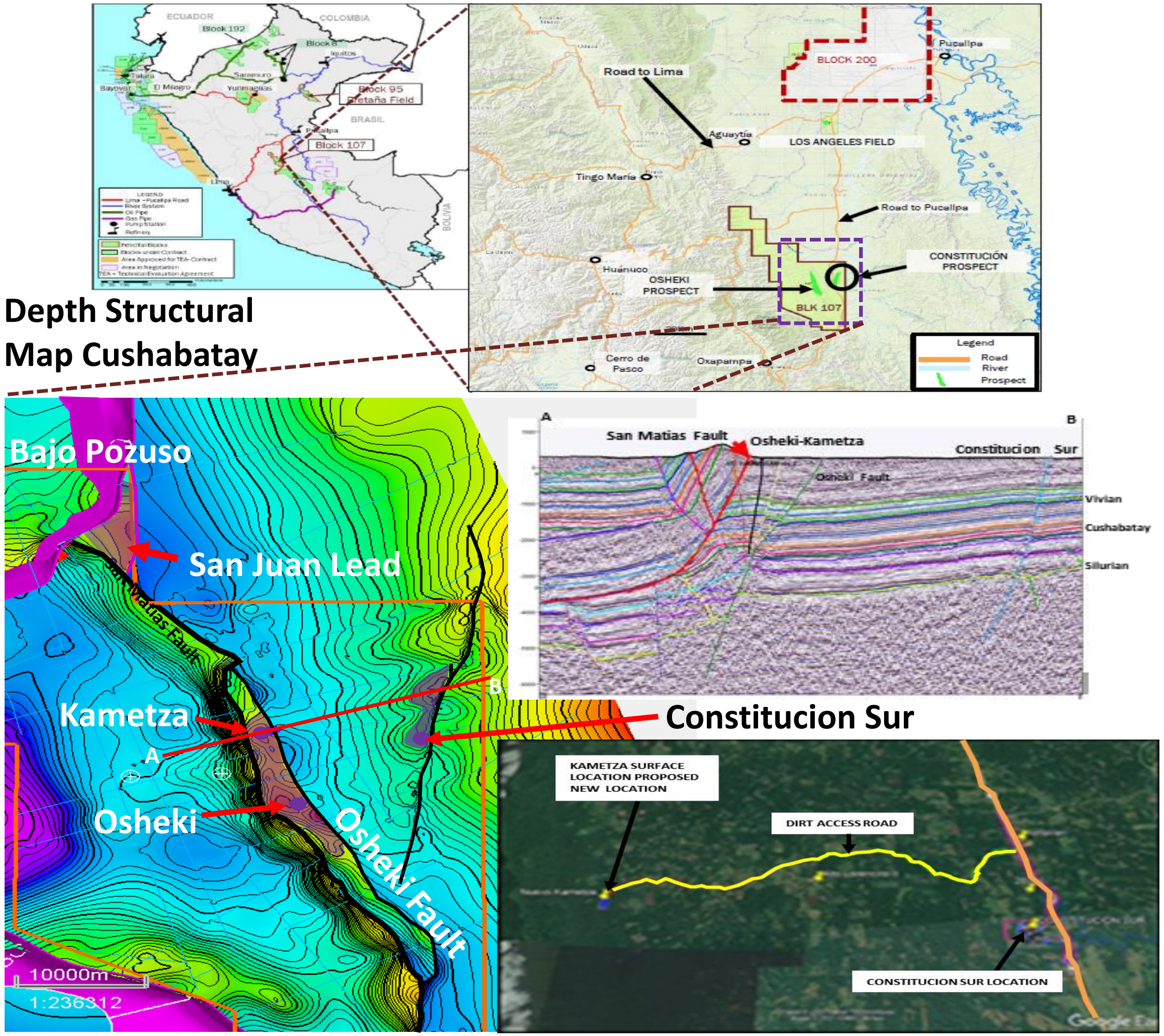
Osheki-Kametza development concept

- 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.
- Exploration commitment to drill two exploration wells extended to 2023
- 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

Technical Summary

Unrisked prospects[1]	Best estimate (mmbbl)	Mean (mmbbl)	Pg (%)
Osheki-Kametza	278.4	534.2	21 - 28
Constitución Sur	31.6	68.5	18 - 21
Unrisked leads[1]	**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**	

Location and structure map

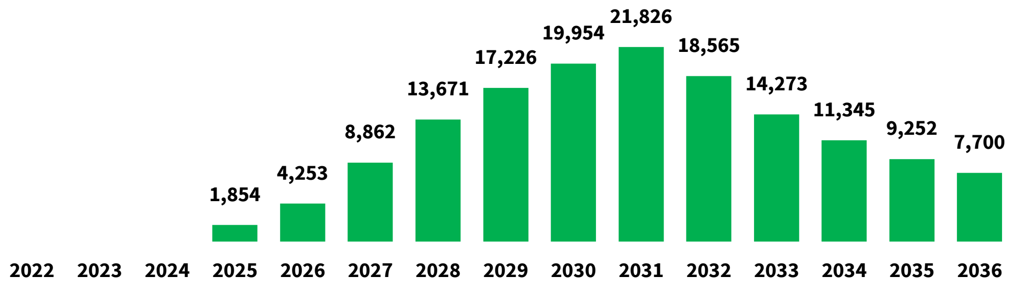


Situation analysis – Osheki Kametza at 50% WI

Minimum case overview[1-5]

- Gross WI technical estimate of ~80 locations @ $8-$10 million per drill using 3.5 mmbbls EUR per well (unrisked)
- Total net WI infrastructure spending of $400 million over length of project and first surface locations
- **Modeled 50% chance of drilling success on 40 net (80 gross) locations**
- **50% WI view**
- **71 mmbbls recovered (net)**
- **First production – late 2025**

Risked production profile (bopd)



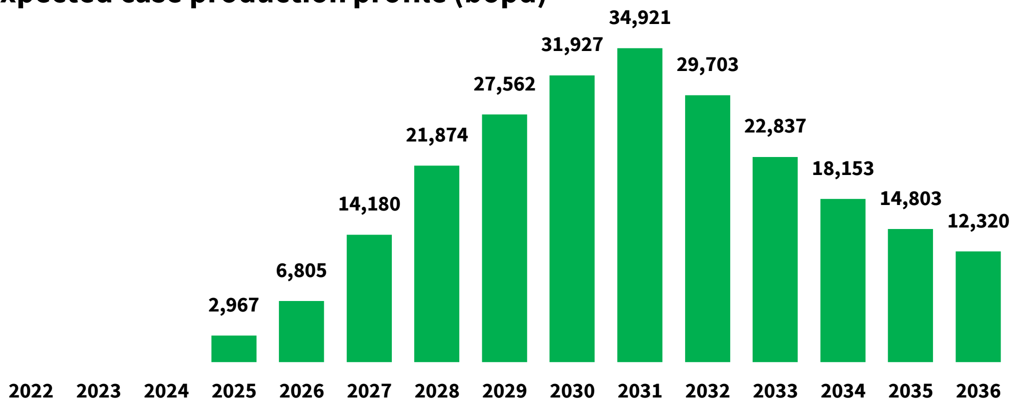
Performance[1-5]

- NPV 10 - $400
- Free cash flow - $1,692
- Project break even – 6 YRs
- Net Project Capex - $765
- Net well count - 40
- PIR – 1.8x
- Capital from Bretaña - $341[2]
- Return of capital life – 6-8 Yrs

Success case overview (Delineated development)[1-5]

- Gross WI technical estimate of ~80 locations @ $8-$10 million per drill using 3.5 mmbbls EUR per well (unrisked)
- Total net WI infrastructure spending of $400 million over length of project including the first surface location
- **Modeled 80% chance of drilling success on 40 net (80 gross) locations**
- **50% WI view**
- **113 mmbbls recovered (net)**
- **First production – late 2025**

Expected case production profile (bopd)



Performance[1-5]

- NPV 10 - $900
- Free cash flow - $3,114
- Project break even – ~2.5 YRs
- Net Project Capex - $765
- Net well count - 40
- PIR – 2.9x
- Capital from Bretaña - $293[2]
- Return of capital ext. – > 10 Yrs

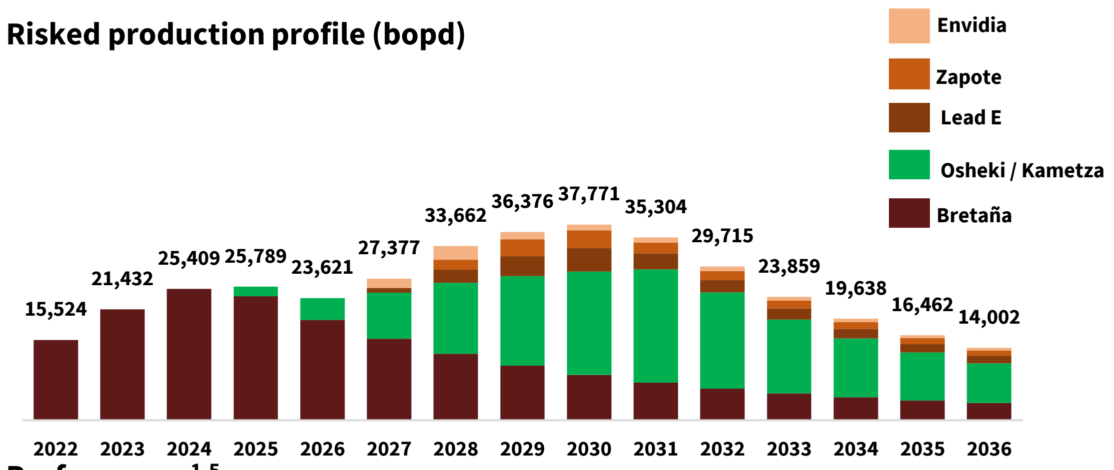
See presentation footnotes in appendix

Situation analysis – PetroTal potential

Risked cases + 2P Bretaña[1-5]

- Modeled 2P Bretaña case (22 gross locations)
- Modeled risked case for Osheki 50% WI
- Modeled risked case for Block 95 expansion 100% WI
- 180 mmbbls recovered (net)

Risked production profile (bopd)



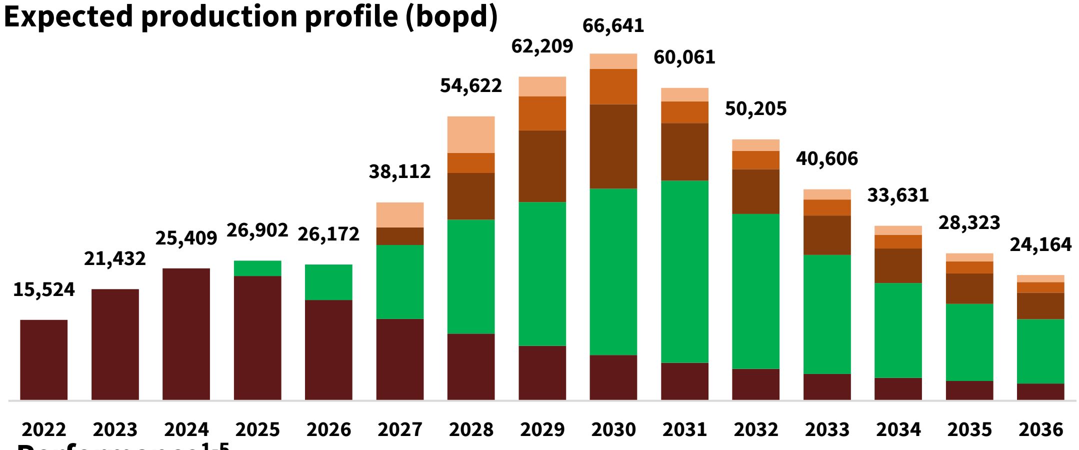
Performance[1-5]

- NPV 10 – 1,639 (inc. Bretaña)
- Free cash flow - >$3,500
- Project break even – N/A
- Net Project Capex - $1,800
- Net well count - 87
- PIR – N/A
- Capital from Bretaña - $560[2]
- Return of capital life ~20 Yrs

Expected success cases + 2P Bretaña[1-5]

- Modeled 2P Bretaña case (22 gross locations)
- Modeled expected case in Osheki 50% WI
- Modeled expected case in Block 95 expansion 100% WI
- 265 mmbbls recovered (net)

Expected production profile (bopd)

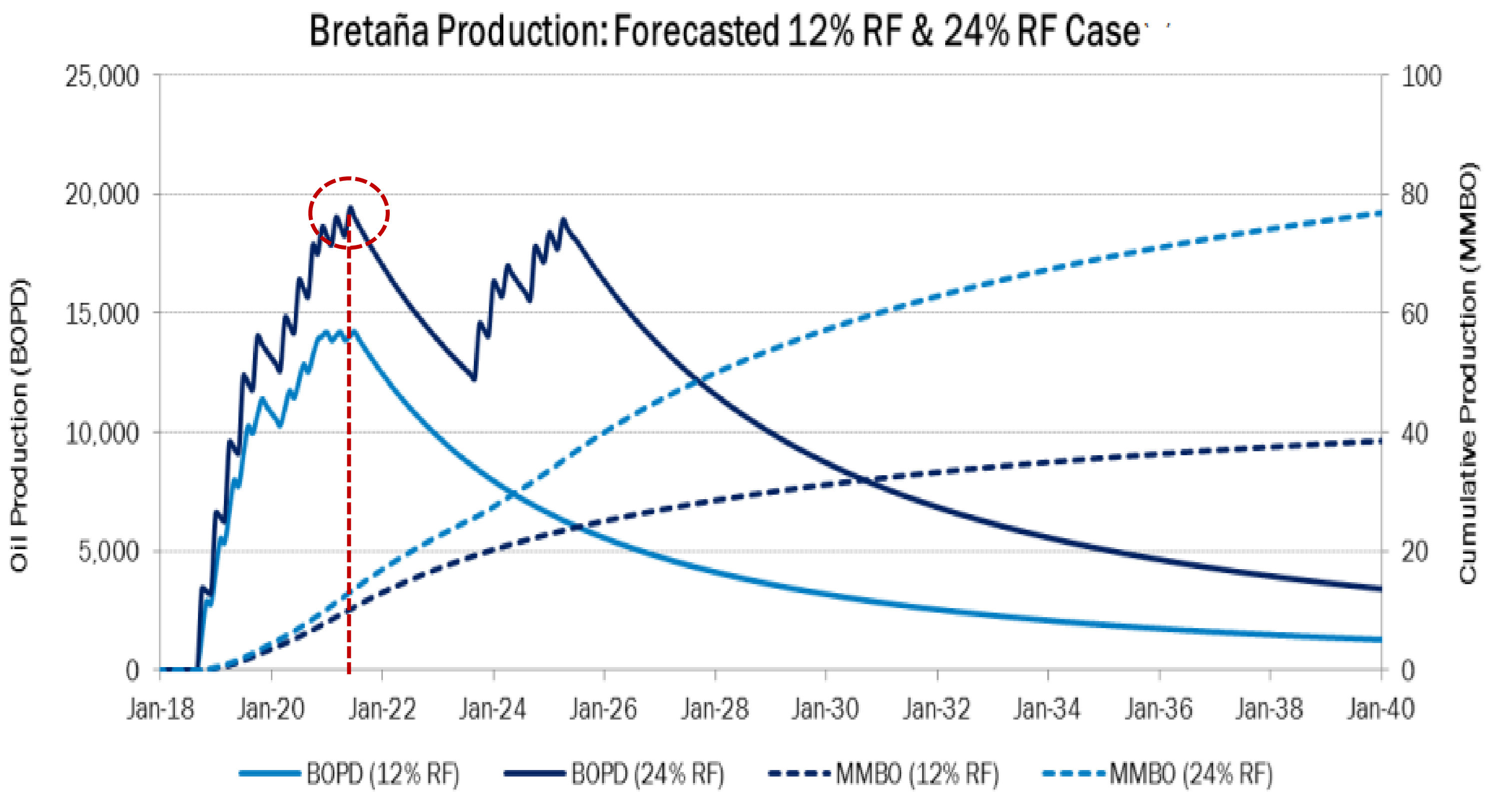


Performance[1-5]

- NPV 10 - $2,669 (inc. Bretaña)
- Free cash flow - >$6,100
- Project break even – N/A
- Net Project Capex - $1,800
- Net well count - 87
- PIR – N/A
- Capital from Bretaña - $400[2]
- Return of capital ext. – ~30 Yrs

Delivering on the 2017 value proposition

*2017 Investor Presentation Snip-it



PetroTal actual - 20,000 bopd mark reached in late 2021, as forecast in 2017

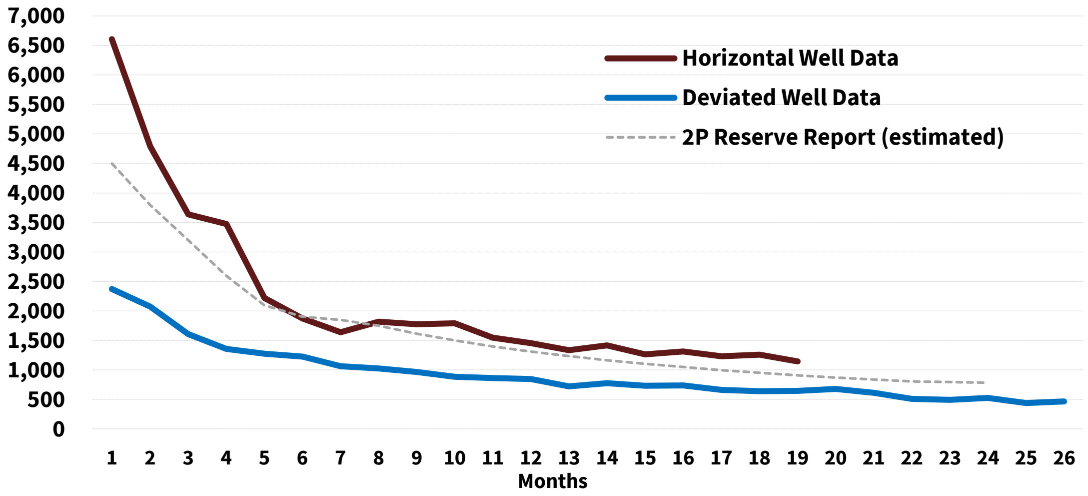
Key highlights

- **2P production plateau now at > 25,000 bopd**
- **3P production plateau now at > 35,000 bopd**
- **PetroTal delivers on target and is on track to significantly outperform its original 2017 investor forecast**
- **PetroTal is the largest crude oil producer in Peru**

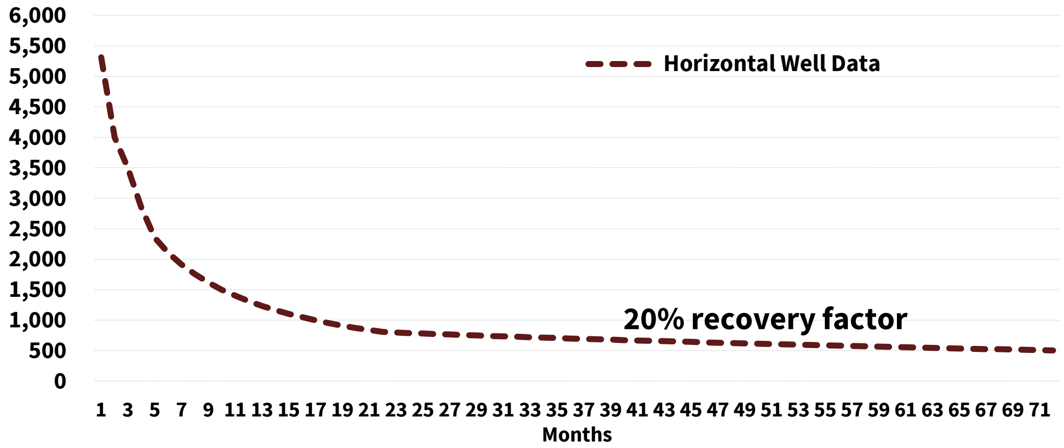
Appendix

Type curve summary

PetroTal (actual) well data (normalized time) (bopd)



PetroTal 2P forecast type curve (bopd)



Well metrics[1-3]

Summary	Horizontal (actual data to Feb 2022)	Estimated 2P Ave (NSAI)	Deviated (actual data to Feb 2022)
IP 90 (bopd)	5,000	3,830	2,019
IP 180 (bopd)	3,800	3,000	1,652
IP 365 (bopd)	2,720	2,290	1,300
EUR (mmbbl)	N/A	4.5	N/A
Capex ($ millions)	$12-$14	$14	$8-$10
Capital intensity (180)	$3,400	$4,667	$5,400
Payout ($90 Brent)	45 days	150 days	45 days
Profit to investment ratio	N/A	>5x	N/A

Key highlights

- Actual portfolio average horizontal data would indicate over performance of NSAI 2P type curve
- Technical team still feels it is prudent to forecast production using near 2P performance
- Robust economics and payout ratios at current Brent levels to justify continued development of 2P/3P booked locations
- Modeling forward looking performance of 10,000 bopd initial production rates would not be recommended, despite well 10H achieving these rates in Feb 2022

Export routes

Multiple export routes preserving pricing optionality[1]

Priority of Sales

25,000 bopd

~16,600 bopd

1. Brazilian Route
- Sold FOB Bretaña at forward 3 month ICE Brent
- Strong netbacks
- Cargos upsized to 400k-500k+ bbl per shipment
- Access to Atlantic market

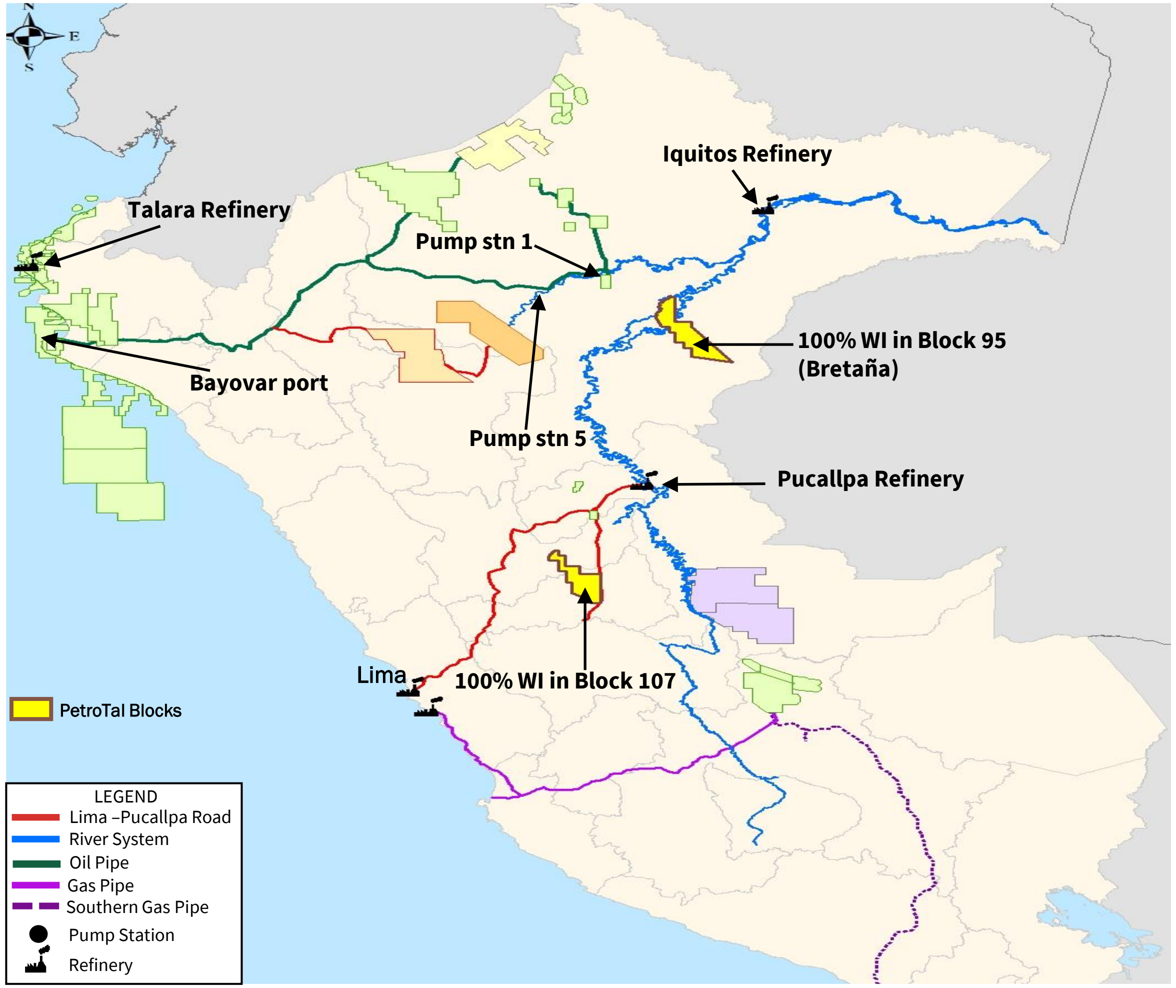
~2,000 bopd

2. Iquitos Route
- Based on spot Dated Brent (premium to ICE)
- 16%-19% diff and transport depending on diluent content
- First 2,000 bopd sold here limited by quality spec of plant

Remaining

3. ONP Route
- Based on forward 8 month ICE Brent
- 3 year contract until December 2022[2]
- ~$4/bbl differential based on most recent export
- ~$13/bbl offtake and commercial
- Access to Pacific market
- Currently down for maintenance until Sept 2022

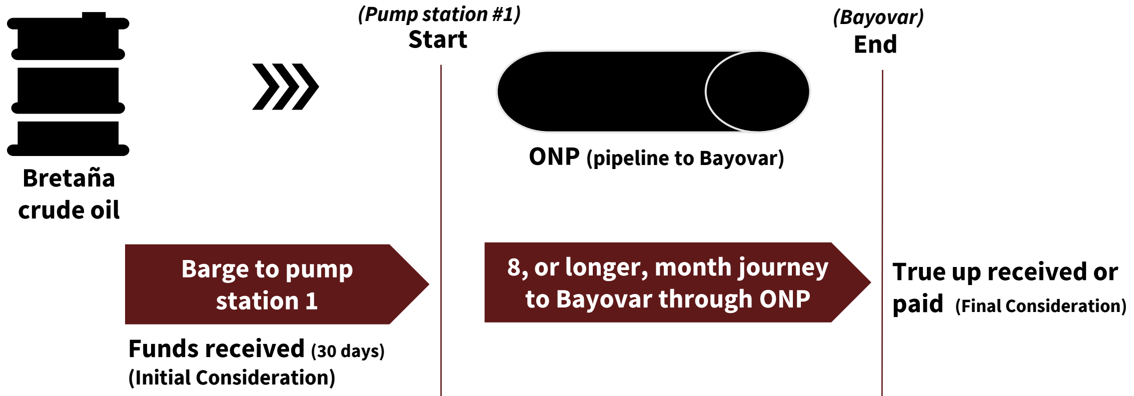
Export Routes[1]



See presentation footnotes in appendix

Oil Sales Commercialization Agreements with Petroperu

Petroperu sales contract illustration (example)



1. Crude leaves Bretaña by barge for pump station #1 (“Delivery Point”)
2. After a short journey, oil ownership is transferred to Petroperu at Delivery Point
3. A valuation of oil is made at the Delivery Point at ICE Brent + 8 months
4. Consideration is immediately paid to PetroTal from a Petroperu credit line costing PetroTal ~3% of revenue (“Initial Consideration”)
5. A differential deduction is estimated and netted with the payment in point 4 based on the most recent actual fiscalization in Bayovar (“Initial Differential”)

1. Oil is not considered completely fiscalized until it reaches Bayovar and a final buyer
2. Once in Bayovar, the oil is valued again at the current ICE Brent spot market (“Final Consideration”) with the appropriate final differential applied (“Final Differential)
3. Petroperu will owe PetroTal a “true up” settlement payment if the Final Consideration > Initial Consideration when oil reaches Bayovar
4. PetroTal will owe Petroperu true up settlement payment if the Final Consideration < Initial Consideration when oil reaches Bayovar
5. Petroperu will owe PetroTal a “true up” settlement payment if the Final Differential < Initial Differential
6. PetroTal will owe Petroperu a “true up” settlement payment if the Final Differential > Initial Differential

Derivative summary March 31, 2022

Summary	Volume Mbbl	Initially paid to PetroTal USD millions	True-up due to PetroTal USD millions
Sales in the ONP pipeline*	3,063	$47.7	$85.7
Petroperu hedging mark to market	831		($21.5)
Corporate hedging mark to market	1,205		($5.5)
Net derivative asset			**$58.7**

**Based on the estimated ONP restart in Sept/Oct 2022, PetroTal is likely to only receive approximately $37 million of in late 2022 with the remainder received in 2023 when sales reach the Bayovar port. ($13 million net gain in 2022)*

True-up revenue received by March 31, 2022

Summary (Bayovar Sales)	Volume Mbbl	Iniatially paid to PetroTal USD millions	True-up paid to PetroTal USD millions
Sales finalized *	1,795	$78.9	$53.0

** Represents three batches of crude since April 2021 which all initially received a Brent price of $44.0/bbl and realized a $65.0/bbl, $82.4/bbl and $87.7/bbl Brent prices respectively, when reaching Bayovar*

Peru fiscal overview

BBB/BBB+/Baa1 stable outlook (Fitch/S&P/Moody's)

- $4 billion in new notes issued late in 2020
- Country risk rating (EMBIG) of 143, the lowest in all Latin America[1]

Rule of law - concession contracts

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

Energy friendly fiscal policy[2]

- Second largest mining sector in the world
- Growing E&P sector with credible oil service companies in country (Baker Hughes, Petrex, Schlumberger)

Favourable royalty rates and social profit sharing

- ~7% at 20,000 bopd with no price scaling + 2.5% social trust payment
- The Peruvian govt. recently announced a $1.7 billion six-year plan to benefit local communities

Robust quality/sales economics

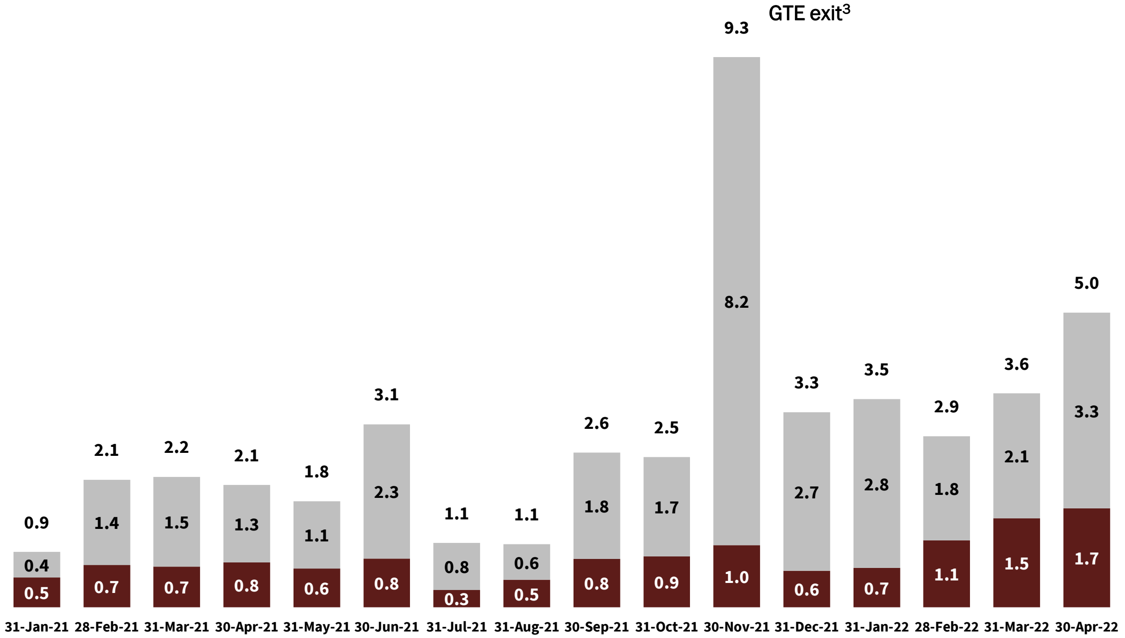
- Differentials range on heavy oil at $2-$5/bbl
- In country refining capacity to materially increase to over 90,000 bopd in the spring of 2022

Talara Refinery (upgrade completed)

- $5 billion upgrade completed in April 2022
- Materially increasing in country demand for crude and pipeline stability
- Attracting international project capital
- Creating associated commercial opportunities for local producers

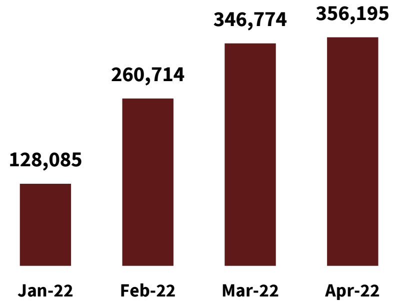
Share ownership and volume

Tal and Ptal daily average trading volume by month (millions)



Major Shareholders[1]	Shares Owned	%
Meridian Capital	154,010,361	18.4%
Kite Lake	87,166,854	10.4%
Burggraben	67,399,012	8.1%
Encompass	54,154,853	6.5%
Fidelity International	42,315,097	5.1%
Total Basic Shares	**836,884,420**	

OTC QX Volume



PetroTal ~16 month trailing share price (CAD/share)

See presentation footnotes in appendix

Management's macro oil view for generalist capital

PetroTal's key data points

- Management teams are now incentivized by deleveraging, returning capital, maintaining production, and ESG
- Until E&P cash flow multiples re rate to 4x-6x, boards and teams can not justify hypergrowth
- US oil, gasoline, distillates inventory deficit to 2016-2019 average down > ~200 million bbls
- OECD total inventories deficit to 2015-2019 average down > ~250 million bbls
- Industry under invested for last 5-7 years. Lack of new material production projects from majors. OPEC underproducing quota (short cycle focused)
- High future Brent price volatility estimated
- Renewables will not displace oil in the near term (10-20 years)
- Population growth, plastics, petrochem, travel demands will keep oil demand growing slowly
- ~40% of oil is not used for transportation purposes

PetroTal decision making impact

- PetroTal will not grow for the sake of growth. Type curve performance with one rig in country will dictate production levels with a commitment to lead ESG
- PetroTal will not add leverage at top of pricing cycle only to possibly pay it back in lower pricing cycles
- Being net debt free, with bullish supply side inventory data will allow the company to potentially hedge less oil production in the future
- PetroTal uses strip pricing for planning purposes with allocation of capital strategies stress tested at 25%-40% lower price decks
- Demand for investment grade short cycle oil projects should be robust over next 10-15 years. PetroTal has 5 other leads/prospects that could be as large as Bretaña

See presentation footnotes in appendix (data from EIA, Peel Hunt, RBC, Ninepoint Energy Partners)

Senior management

Experienced and seasoned 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

Doug Urch – *Executive Vice President & Chief Financial Officer*

- Previously Executive Vice President, Finance and Chief Financial Officer of Bankers Petroleum Ltd
- Chartered Professional Accountant (CPA) and a designated member of the Institute of Corporate Directors (ICD)
- Director of PetroTal since inception and was Chairman of the Board from June 2018 until November 2019

Dewi Jones – *Vice President, Exploration and Development*

- Over 35 years of Latin American oil and gas experience with focus on designing and executing exploration & production programs including bringing new discoveries to initial production
- Multiple senior technical and management level roles with Occidental and Repsol, focussed on developing and exploring assets across Latin America
- Former CEO of CGX Energy

Board of directors

Highly experienced governance[1]

Mark McComiskey – *(Non-Executive Director and Chairman)*

- Partner of Avaiocapital 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

Gary Guidry – *(Non-Executive Director)*

- President & CEO of Gran Tierra with >35 years as a Engineer with APEGA
- Former President & CEO of Caracal Energy, Orion O&G, Tanganyika Oil
- Senior op. roles at Occidental in Nigeria/West Africa, Yemen and Venezuela

Ryan Ellson – *(Non-Executive Director)*

- CFO of Gran Tierra and >15 years experience as a Chartered Accountant
- Former Head of Finance at Glencore E&P Canada and VP Finance at Caracal Energy

Gavin Wilson – *(Non-Executive Director)*

- Investment Manager for Meridian
- Former founder & manager of RAB Energy & RAB Octane listed investment funds

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

Roger Tucker – *(Non-Executive Director)*

- 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

1) *Manolo Zúñiga, President and Chief Executive Officer, is also a director of the company with his bio referenced on slide 43*

DISCLAIMERS

Forward-Looking Information

Certain information included in this presentation constitutes forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project” or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this presentation may include, but is not limited, statements about: the Company’s corporate strategy, objectives, strengths and focus; potential exploration and development opportunities; processing capacity, including pursuant to a proposed expansion of central processing facilities (CPF#2); expectations and assumptions concerning the success of future drilling, development, transportation and marketing activities; storage capacity; access to diversified markets, including pursuant to multiple export routes; intention of engaging joint venture partners to drill the Osheki prospect; the performance, economics and payouts of new and existing wells; decline rates; recovery factors; the successful application of technology and the geological characteristics of properties; capital program and capital budgets, including revised 2022 guidance and budget; future production levels and growth, including 2022 exit production, 2022 average production; cash flow; debt; shareholder return strategy; primary and secondary recovery potentials and implementation thereof; potential acquisitions; regulatory processes; drilling, completion and operating costs; commodity prices and netbacks; realization of anticipated benefits of acquisitions; hedging program; NPV-10 valuations; the performance of the management team and board; and ESG and CSR activities and commitments. Statements relating to “reserves” and “prospective resources” are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves or prospective resources described exist in the quantities predicted or estimated and that the reserves or prospective resources can be profitably produced in the future. Without limitation of the foregoing, future dividend payments, if any, and the level thereof, is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, free cash flow financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of PetroTal to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness.

The forward-looking information is 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, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal’s products, the availability and performance of drilling rigs, facilities, pipelines, equipment, other oilfield services and skilled labor, royalty regimes and exchange rates, 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, the Company’s growth strategy, general economic conditions, prevailing commodity prices and future debt and equity financings. 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. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

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, stock market volatility, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration, production and transportation; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety, environmental and regulatory risks), commodity price and exchange rate fluctuations, actions of OPEC and OPEC+ members, 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. In addition, the Company cautions that current global uncertainty with respect to the spread of the COVID-19 virus and its effect on the broader global economy may have a significant negative effect on the Company. While the precise impact of the COVID-19 virus on the Company remains unknown, rapid spread of the COVID-19 virus may continue to have a material adverse effect on global economic activity, and may continue to result in volatility and disruption to global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company. Please refer to the risk factors identified in the Company’s most recent annual information form and management’s discussion and analysis which are available on SEDAR at www.sedar.com. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking information. The forward-looking information contained in this presentation is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking information contained in this presentation is expressly qualified by this cautionary statement.

Financial Outlook

This presentation contains future-oriented financial information and financial outlook information (collectively, “FOFI”) about PetroTal’s prospective results of operations, production, enterprise value, payout of wells, CAPEX, net debt, cash flow, EV/cash flow, free cash flow after debt service, capital efficiency, balance sheet strength, netbacks, EBITDA, net debt to annualized EBITDA, NPV-10, EUR, operating costs, break-even Brent oil price, royalties, corporate tax, tax pools and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumption outlined in the Non-GAAP measures section below. FOFI contained in this presentation was approved by management as of the date of this presentation and was provided 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 presentation, 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 presentation should not be used for purposes other than for which it is disclosed herein.

Forward looking CAPEX and OPEX assumptions in this presentation are consistent with the NSAI Reserve Report as at Dec 31, 2021 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.

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, 2021 (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.

DISCLAIMERS (CONTINUED)

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.

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. *R*epresents 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 cash flow” defined as EBITDA before hedging minus CAPEX. “Free cash flow after debt service” defined as EBITDA less interest and CAPEX (all estimated). “Yield” means free cash 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	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		
bopd	barrel of oil per day	Free Cash Flow	EBITDA less CAPEX or as defined in footnotes		
k bopd	Thousand barrel of oil per day	FFO	Funds flow from operations		
F&D	Finding and development costs	Adj. EBITDA	Earnings before interest, taxes, depreciation, amortization, and after derivative adjustments	EBITDA	is Adj. EBITDA prior to derivative impacts
NIBD	Net interest bearing debt	Ha	Hectares		
		PDP	Proved Developed Producing Reserves		
Mmbbl	Million barrels of oil	1P	Proved Reserves		
NGL	Natural gas liquids	2P	Proved + Probable Reserves		
bbo	Billion barrels of oil	3P	Proved + Probable + Possible Reserves		

Footnotes

Slide 2
1. *Market capitalization as at May 23, 2022 using a 1.28 CAD/USD exchange rate*
2. *Net debt estimated as at March 31, 2022(not calculated for bond covenant purposes)(all long and short term liabilities excluding decommissioning less total cash, all receivables, and short and long term derivative assets)*
3. *NSAI Reserves statement effective date December 31, 2021*
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
1. *Booked well counts for 2P and 3P references are per NSAI Reserves statement effective December 31, 2021*
2. *Capital efficiency calculated as $13 million well cost / 2,800 bopd (IP365 on average new horizontal)*

Slide 4
1. *Production in bopd is average for the year indicated*
2. *On initial share price from reserve take over of Sterling Resources*

Slide 5
1. *NSAI Reserves statement effective date December 31, 2021, gross including oil used in the field in each category. PDP defined as proved development producing reserve category. PUD defined as Proven undeveloped reserve category. Prob defined as probable. Poss defined as possible.*
2. *The 3P reserve case would require additional facilities investment and would require environmental impact assessment permits ("EIA") from the Peruvian government*
3. *Per share values used 828.2 million shares outstanding as at Dec 31, 2021*
4. *Recovery factors must include historical production on top of estimated reserves (ultimate recovery)*

Slide 6
1. *Source – 2020 Sustainability Report (see company website)*

Slide 9
1. *Per the NSAI Reserves statement effective date 31 December 2021*
2. *AICD – Autonomous Inflow Control Devices*

Slide 10
1. *Drilling schedule subject to changes based on field operating conditions*
2. *Dates are estimated*
3. *"Spud" refers to the start of drilling*

Slide 11
1) *See disclaimers – Non GAAP financial measures*
2) *B_0 refers to original presented budget and B_1 refers to revised guidance*
3) *Sales to Iquitos and Brazil assumed at 2,000 and 11,500 – 16,500 bopd respectively. Remainder of sales assumed to ONP*
4) *Net Operating Income ("NOI") = Revenue less differentials, transportation fees, commercial fees, royalties, and operating costs*
5) *Free cash flow defined as NOI less G&A less capex before any debt service or other cash costs (see disclaimers – Non Gaap financial measures)*
6) *G&A includes $4 million of new social and community project funding*
7) *Net true-up revenue and derivative impact not included in free cash flow matrix*

Footnotes

Slide 12

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 markets are on a monthly basis, thus allowing for maximum recurring sales of 16,600 bopd of average production assuming no issues at the Puinahua Channel or in the field*
4. *Currently being expanded from 240k to (400k - 500k bbls)*
5. *If economically viable and under regular payment term conditions from Petroperu and normal dock access*

Slide 13

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, 2021 3P volumes in the reserve report, additional injection capacity equipment is required*

Slide 14

$8 million assumed to include bond interest saved on early retirement, refinancing fees on required new debt and interest expense on that new debt, and a higher call premium penalty on the earlier retirement

Slide 15

See disclaimers – Non Gaap financial measures

Slide 15

1. *Production data in table as at May 2022*
2. *All type curve recoveries are internal estimates and calibrated to the December 31, 2021 NSAI reserve report*

Slide 24

1. *Production profiles at May 2022*
2. *See disclaimers – Non Gaap financial measures*

Slide 25

1. *See disclaimers – Non Gaap financial measures*

Slide 26

1. *Short and long term debt includes all liabilities excluding decommissioning. Estimated year end cash balance is net of full bond repayment*
2. *Adjusted Net debt (see slide 2 footnotes) (not used for covenant purposes)*
3. *See disclaimers – Non Gaap financial measures*
4. *$62 million discretionary cash flow return of capital subject to board approval and economic viability and shown for illustrative purposes.*

Slide 27

1. *Average Brent assumed at $102/bbl contracted . Brazil commercial contract specifies Brent + 3 month pricing. Saramuro commercial contract specifies Brent + 8 month pricing*
2. *Production allocations by sales route are estimated and subject to material change depending on market conditions*
3. *Differential is estimated*
4. *EBITDA defined as Netback less G&A (See disclaimers non gaap financial measures)*
5. *2022 G&A includes $4 million ($0.6/bbl) of social and community projects*
6. *Assumes the ONP is operational Oct 1, 2022 and not subject to further downtime for any reason*

Slide 28 - 30

1. *Performance type curve applied to existing wells based on internal calibration with the Dec 31, 2021 year ended NSAI reserve report*
2. *Free cash flow is pre tax and before debt service or derivative impact (see disclaimers – Non Gaap financial measures)*
3. *Capex, EBITDA, and free cash flow in 2018 were $23 million, ($1.1 million), and ($24.1 million) respectively*
4. *Other cash burdens defined as interest, factoring, lease payments, taxes and derivative settlements*
5. *Uses May 5, 2022 Brent strip*

Footnotes

Slide 31
1. *Best estimate = 26 mmbbls (modeled assumption 100% of best estimate and 40% of mean)*
2. *Production and cash flow profiles are internal management estimates and have not been confirmed or reviewed by a third party reserve evaluator and are subject to change based on management confirming assumptions in the future*
3. *See disclaimers (Non Gaap financial measures)*
4. *PIR = profit to investment ratio (PV of cash flows / PV of Capex)*
5. *Cash from Bretaña indicates the project funded gap required to be backfilled by equity, debt, or cash from Bretaña*

Slide 32
1. *Best and mean estimates per NSAI resource assessment effective date of June 2020*

Slide 33, 34
1. *Best estimate = 278 mmbbls (modeled assumption 50% and 80% of best estimate)*
2. *Production and cash flow profiles are internal management estimates and have not been confirmed or reviewed by a third party reserve evaluator and are subject to change based on management confirming assumptions in the future*
3. *See disclaimers (Non Gaap financial measures)*
4. *PIR = profit to investment ratio (PV of cash flows / PV of Capex)*
5. *Cash from Bretaña indicates the project funded gap required to be backfilled by equity, debt, or cash from Bretaña*

Slide 37
1. *Production data in table as at Feb 8, 2022*
2. *All type curve recoveries are internal estimates*
3. *Capital intensity 180 = Capex / IP 180*

Slide 38
1. *PetroTal has delivered Bretaña crude oil to Bayovar through Yurimaguas port with subsequent trucking to Bayovar of 4,000 bopd. Also an additional 2,500 bopd delivery option to Conchan Refinery exists with subsequent barging to Pucallpa and trucking to Lima. Both options require access to the rivers, additional infrastructure upgrade by Petroperu and approval from Petroperu*
2. *Extended in June 2020 and automatically extends with force majeure events*

Slide 40
1. *2022 E&Y Peru Investment Guide. (Chile 147, Colombia 210, Brazil 255 country risk ratings)*
2. *PetroTal has over $280 million of tax loss carry forwards in Peru and over $70 million in Canada*

Slide 41
1) *Shareholders per April 25, 2022 (AIM rule 17 per PetroTal website)*
2) *Trading data source per TSX-V, OTC QX and AIM ending April 30, 2022*
3) *On Nov 26, 2021 GTE sold an aggregate of 137,093,750 common shares in PetroTal*

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