PTTEP Q3 2022 Analyst Meeting

Edited Transcript

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Speakers:

Khun Montri Rawanchaikul
Chief Executive Officer

Khun Natruedee Khositaphai
Executive Vice President – Strategy and Business Development Group

Khun Sumrid Sumneing
Executive Vice President, Finance and Accounting Group

The slides of the presentation, as referenced throughout the transcript, can be found here.

Introduction

Moderator

Welcome to PTTEP's Analyst Meeting, featuring the announcement of the Company's operating performance in the third quarter of 2022. Before we begin, please allow me to introduce the executives who will be delivering the presentation today; 1) Khun Montri Rawanchaikul, Chief Executive Officer, who will share with us key highlights on energy transition, balances of energy from different sources under the Energy Trilemma, and PTTEP's key roles to deliver Security & Affordable Energy for Thailand, 2) Khun Natruedee Khositaphai, Executive Vice President – Strategy and Business Development Group, who will discuss the market outlook for oil and LNG businesses, an update on key projects' milestones and the progress on the reduction of greenhouse gas emission under the Company's mission to achieve Net Zero by 2050, and 3) Khun Sumrid Sumneing, Executive Vice President – Finance and Accounting Group, who will summarize PTTEP's financial performance in the third quarter of 2022, financial position, and the financial outlook for 2022. Without further ado, please join me in welcoming our CEO to commence the presentation.

PART 1: CEO Remarks

Khun Montri Rawanchaikul,
Chief Executive Officer

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CEO Remarks:

Another quarter passed and once again we gather here today to update key highlights on the Company's performance, which I believe many of you may have already reviewed.

At this point, PTTEP's business direction has never been clearer as a key player in securing national energy stability. We have performed our duties in the economic aspects by paying taxes and royalties over 70,000 million Baht (circa 190 million USD), while the Company's performance has continued to drive the country's economic prosperity and viability.

As we all know, every country is facing energy crisis in one way or another from the recent global issues. Amidst this sentiment, PTTEP has explicitly announced the EP Net Zero by 2050 with concrete execution plans, for instance, Carbon Capture Storage (CCS) and Carbon Capture Utilization (CCU). Meanwhile, we are taking the lead role in these endeavors in several countries we operate.

Moreover, as we highly emphasize on technology, our subsidiary, ARV, has started to generate revenue under its solid execution plan.

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Energy Trilemma:

Before we go further, I would like to address the matter of energy crisis, of which I had an opportunity to attend a global conference in London 2 weeks ago. CEOs of major companies all shared the same thoughts and ideas based on the energy trilemma. There are 3 dimensions to achieve balance in the global energy landscape; Security – something that every country aspires to achieve, Sustainability – issues related to climate change, global warming and even the discussion on quitting fossil fuel-based energy, and lastly Affordability – or rising energy prices; if it were to reach at the balance point, it should be in the middle of the triangle.

Though we are still relying heavily on fossil fuels, we have gradually adjusted our portfolio and incorporated a higher portion of gas as we believe gas is a transitional energy from fossil fuel to future energy.

At the same time, renewable energy is also being capitalized on by many players globally, though the cost, pricing and technology will have to be balanced out with those of the conventional energy sources. Hence, based on this energy trilemma, we anticipate seeing something that is Secure, Sustainable and Affordable. At this point, balance has not yet been achieved and it is our commitment to get there.

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Gas as Transitional Fuel to Low Carbon Energy Future:

In terms of the energy mix and future energy trend, oil consumption is likely to decline as people are changing to EV. Though we can see an increased coal consumption recently, the utilization trend is expected to decrease in the long term, with a promising growth of renewable energy and gas. Demand growth in gas may seem to be good news, but there is quite a large gap between LNG demand and supply; given a potential demand surge in the next 20 years despite limited supply. With this, we can see many countries' decision to go ahead with the investment in LNG projects, as appeared in recent news in Qatar and in Thailand. Hence, the gap between gas demand and supply still remains a significant issue in keeping energy cost at a pretty high level.

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Deliver Security & Affordable Energy to Thailand:

Thailand gas demand in 2022 for electricity generation and industrial sector is approximately 4,300 mmscfd. With major gas fields in Thailand; Erawan (G1/61), Bongkot(G2/61), Arthit and Pailin Project, and other joint development areas such as MTJDA in Malaysia, and gas supply from Yadana and Zawtika in Myanmar, all of which constitute a total gas supply of about 2,600 - 2,700 mmscfd against the demand of 4,300 mmscfd, including natural gas supply imported from Myanmar of 686 mmscfd and LNG of 969 mmscfd, which may exceed 1,000 mmscfd on certain days depending on the level of demand and supply.

In terms of natural gas price, Thailand pool price is displayed in blue line; taking into account gas prices of Myanmar, MTJDA, and Gulf of Thailand projects, which is not high. However, the high energy price is a result of LNG demand and supply imbalance. Gas supply disruption from Russia, that is widely affecting demand in Europe, consequently causing people to resort to LNG instead. With high LNG demand, price increases, subsequently causing a rise in the pool price as well.

A portion of LNG is usually procured under the contract, and another portion is procured under the spot price; which is beyond the role of PTTEP. PTTEP's role is to ensure production security in the Gulf of

Thailand and neighboring countries, for which there are markets and mechanisms to accommodate our production. Hence, it is our priority to produce sufficient amount of gas to cover the demand.

As you might have already been aware of, the access to G1/61 Project has been delayed for about 2 years, coupled with the shutdown of several fields. We have been doing our best to accelerate production, marking a historical milestone for PTTEP for having as many as 10 rigs in the Gulf of Thailand, before adding one more in 2023, making it 11 rigs altogether.

In ramping up production at G1/61 Project, there are a number of required activities; installation of production platforms and pipelines, drilling more producing wells, and setting up safety equipment. All of these usually take about 2 years, and we expect to see increased production by the second quarter of 2023. We anticipate to achieve the production of 800 mmscfd by April 2024; about 18 months from now.

We have always put priority on maximizing gas production of our existing assets, to serve domestic consumption, with well-established markets mechanisms. Therefore, we try to accelerate every outstanding tasks as much as we can, as seen from increased production at Arthit Project, successful negotiation for the MTJDA Project to supply 30 mmscfd of gas to Thailand. We are of the view that combined production at Arthit, G2/61 and MTJDA Projects is likely to exceed our goal; amounting to approximately 200 mmscfd. Once again, we hereby reiterate our mission to ensure energy security for the country and PTTEP's significant mission in making it happen.

Having said that, the high electricity cost is not the result of high gas price in the Gulf of Thailand, but rather because of higher portion of imported LNG. With high level of global LNG spot price, the average pool gas price then increased as shown in the green-colored line.

Next, Khun Natruedee will share with you the oil and LNG market outlook and our business progresses.

PART 2: Business Update

Khun Natruedee Khositapha,
Executive Vice President – Strategy and Business Development Group

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Market Update:

If you have been following the news, crude oil price in the third quarter started to decrease due to the economic recession fears, demand and the increase in interest rates by global financial institutes. On the other hand, supply is likely to remain consistent from Russia and the USA, hence we can see a certain degree of balance between supply and demand at this point.

From the beginning of the year, the average crude oil price is slightly below 100 USD/barrel, despite a minor drop in the third quarter. Going forward, we expect crude oil price to remain in the range of 90-100 USD/barrel in the fourth quarter.

LNG price has continuously been on the rise, with the average price in the third quarter of 45-46 USD/MMBTU, supported by summer demand for temperature control. As winter is approaching, LNG price is likely to increase in the upcoming fourth quarter for heating applications. In the meantime, with the increased supply from previously delayed projects, we expect that the balance between demand and supply can still be sustained.

However, we still have to closely monitor market factors; economic factors, inflation, recession and COVID-19 measures in China. Besides, many countries including the OPEC+ are still exercising control over supply, as seen from a number of measures being released. Last but not least, the geopolitical situations are another area that we need to keep monitoring.

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Projects Update Q3/2022:

With regards to key projects' progress, G1/61 Project has current gas production at 210 mmscfd, with the first ramp-up target in the middle of 2023. We have already installed 4 wellhead platforms, with another 4 wellhead platforms to be installed by the end of the year.

We have been granted a license for additional exploration area for the MTJDA Project, with a 10-year PSC extension to 2039 to support increasing gas demand in Thailand. We articulate an additional gas volume of at least 30 mmscfd to Thailand through to 2025.

For SK410B Project in Malaysia, the exploration campaign is to be continued, with another exploration well under result evaluation.

Meanwhile, there was a gas pipeline leakage at Zawtika Project in Myanmar. However, we managed to get it repaired within 2 weeks and resumed normal operations.

Moving on to the Middle East assets, we have announced the gas discovery at Abu Dhabi Offshore 2 Project in the UAE, with the forecasted gas reservoir of 2.5-3.5 TCF, which is quite significant, though further drillings to appraise the full block's potential are to be continuously executed.

We have commenced oil production at Algeria Hassi Bir Rekaiz Project (HBR), expecting to yield daily production of approximately 13,000 barrels per day in the fourth quarter.

For Mozambique Project, we are awaiting the security situation to settle down in order to resume operations as planned. And last but not least, we are now under the process of divesting our assets in Brazil as part of the portfolio rationalization plan.

Another key event worth highlighting is that PTTEP is participating in the 24th Gulf of Thailand bid round to operate G1/65, G2/65 and G3/65 blocks with 2 PSC schemes: exploration 6+3 years and production 20+10 years. Upon submission of the bids since the middle of September, the announcement of successful bidder will be made in early February 2023.

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Pathway to Decarbonize:

PTTEP has already announced the Net Zero goal by 2050, with 3 strategic pathways to facilitate achievement of the goal; avoid, mitigate and offset.

In the parts concerning 'avoid and mitigate', the focus is on enhancing our operational efficiencies, minimizing leakages of greenhouse gases and the use of renewable energy in our operations. Given our goal to reduce the greenhouse gas by 25% within 2030, we have now managed to achieve such goal by 8 years in advance. The new base year has been set to 2020 following the new targets. In order to materialize Net Zero by 2050, the greenhouse gas emission intensity will be reduced further by 30% within 2030, and 50% within 2040, to ultimately achieve Net Zero in 2050.

From beginning of this program implementation in 2012 to date, the accumulated greenhouse gas emission reduction was reported at 2.77 million tons of CO2 equivalent. Key projects that support this endeavor are, for instance, S1 solar project, with current progress of 60% and the expected completion in the second quarter of 2023. Another featured project is Arthit CCS, whereby the pre-FEED study is underway, with the first injection planned in 2026. And as part of our portfolio management, we have set clear directions for future investment decision to ensure that everything goes on as planned.

The part concerning avoiding and mitigating alone may not guarantee net zero greenhouse gas emissions, so we need to do the offsetting part as well. We have continuously been planting mangroves along the coastal lines as well as onshore forests, which can greatly absorb carbon dioxide. In doing so, we have been granted an approval from the Department of Marine and Coastal Resources to plant 4,000 rais of mangrove forests in southern provinces, Chumporn, Nakhon Si Thammarat and Surat Thani. Our plan is to plant up to 45,000 rais of mangrove forests within the next 10 years.

Apart from that, we have completed a pilot-scale seagrass plantation study in Koh Taen. Seagrass is a highly effective carbon dioxide absorber, though not easy to plant. Therefore, we have collaborated with Kasetsart University to determine the best way to make them survive sustainably. Additionally, we are executing an ongoing study of carbon absorption of seaweed, seashells and coral reef in Thailand in collaboration with Chulalongkorn University.

Given our commitment to be a low carbon organization, PTTEP takes pride in receiving the 2022 Low Carbon and Sustainable Business Award in the highest level from the Thailand Greenhouse Gas Management Organization (TGO).

For the last section, Khun Sumrid will share with you Q3/22 financial results as well as the outlook for 2022.

PART 3: Financial Results

Khun Sumrid Sumneing,
Executive Vice President – Finance and Accounting Group

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Profit & Loss:

The net profit in the third quarter increased to 664 million USD, and 1,581 million USD as of 9M22. In terms of key activities, there was a write-off of exploration wells in Australia, incurring an expense of approximately 29 million USD, which was reflected in the third quarter's financial statement.

Then, we had a 10-year production period extension for MTJDA project, essentially contributing higher volume in 2022. Meanwhile, there were tax incentives recognition from Sabah H Project in Malaysia. Such incentives are for deep-water wells of more than 200 meters, which has contributed to tax saving in the third quarter of about 52 million USD.

We have signed a Sale and Purchase Agreement for the divestment of assets in Brazil. Since the deal has not yet been officially completed, those assets are still on the balance sheet as 'asset held for sale', and the impairment of about 95 million USD was booked in Q3/22 accordingly. The increase in net profit of 64 million USD QoQ, essentially contributed from the improvement in sales volume from G1's full-quarter contribution and less shutdown days at MTJDA, all in all contributing to an increase in volume of 3%.

The average selling price in the third quarter declined by 3% QoQ mainly from the lower liquid price, while the unit cost remained quite flat compared to the second quarter.

As for non-operating items, the decrease in oil price usually entailed oil price hedging gains of approximately 94 million USD in the third quarter as a result of the reversal of the mark-to-market arrangement, as opposed to the oil price hedging loss of about 38 million USD in the second quarter due to the rising oil price back then, while an impairment of Brazil's assets of 95 million USD was booked in the third quarter.

Compared to the same quarter of 2021, the net profit increased YoY from 292 million USD in Q3/21 to 664 million USD in Q3/22, largely due to volume contributions from G1/61, Oman Block 61 and Arthit. Without a doubt, the average selling price increased significantly YoY from higher gas and liquid prices, despite a slight drop in the unit cost due to the contribution of Oman Block 61, G1/61 and Bongkot. Likewise, there was an oil price hedging gain of 94 million USD in Q3/22, compared to an oil price hedging loss of about 41 million USD in Q3/21 due to the fact that the oil price was on the rise last year. However, in Q3/22, the impairment of Brazil's assets of 95 million USD was recognized.

On a 9-month perspective, the net profit increased from 890 million USD as of 9M21 to 1,581 million USD as of 9M22 from 10% increase in sales volume. Similarly, the average selling price increased by 27% while the unit cost declined by 1%.

Since the oil price increased at a slower rate than it did in 2021, less oil price hedging losses were reported as of 9M22. In 2021, a portion of assets in Brazil were written off, approximately 145 million USD, followed by additional impairment of 95 million USD in 2022, resulting in a complete divestment of the portfolio in Brazil. In the meantime, since there were gains from bargain purchase of approximately 350 million USD in Q1/21, the amount of loss in 2022 then seemed quite substantial.

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Volume and Price:

Production volume increased by about 3% QoQ from 465 KBOED in Q2/22 to 478 KBOED in Q3/22, mainly contributed from G1/61, G2/61 and MTJDA, though the volume from G1/61 and G2/61somehow have been offset by the missing volume from Bongkot. Contributions from assets in Southeast Asia are from increased stakes in Yadana following Total's withdrawal and increased production in Malaysia.

In a similar manner, production volume increased YoY from 417 KBOED in Q3/21 to 478 KBOED in Q3/22, enabled by contributions from G1/61, G2/61 and Bongkot, as well as an increased DCQ for Arthit from 260 KBOED to 280 KBOED, coupled with productions from Yadana and assets in Malaysia.

On a 9-month perspective, the production volume increased from 414 KBOED at 9M21 to 457 KBOED at 9M22, taking into account 3 full quarters worth of production from Oman Block 61 and Block H that has commenced production since February 2021, as well as frequent contributors: G1/61, G2/61 and Bongkot.

In terms of price, the average Dubai crude price in 2021 was reported at around 69.39 USD/barrel, increasing to 108.22 USD/barrel in Q2/22 and dropping to 96.68 USD/barrel in Q3/22. The crude oil price scenarios have had a direct impact on our liquid price; 105.47 USD/barrel in Q2/22 and 97.94 USD/barrel in Q3/22. Speaking of which, liquid price is usually discounted by about 2-3 USD/barrel from Dubai crude price. Nevertheless, we can notice a premium over Dubai in the third quarter, whereby there is a certain block in Oman field whose pricing was set from the beginning of the quarter or 2 months prior, which was somewhere over 100 USD/barrel, consequently pushing liquid price in the third quarter above that of Dubai crude. But it is still lower than the 9-month average price of 98.44 USD/barrel; approximately 2 USD/barrel discounted from Dubai crude price of 100.29 USD/barrel.

Gas price also increased QoQ from 6.1 USD/MMBTU in Q2/22 to 6.18 USD/MMBTU in Q3/22, which has been forecasted to be around 6.7-6.8 USD/MMBTU in the fourth quarter as there will be a regular price adjustment, which usually reflects the pricing in the past 6-12 months, so it might be slightly higher than in the third quarter.

That is the overall pricing situation in the past quarter, with only a minor drop in the weighted average selling price from 55.61 USD/barrel in Q2/22 to 53.68 USD/barrel in Q3/22. However, we can notice a significant increase YoY from 42.34 USD/barrel at 9M21 to 53.62 USD/barrel at 9M22, providing an explanation for a major increase in the net profit so far.

The volume mix between gas and liquid is about the same at 73% and 27% respectively, while revenue contribution from gas and liquid is also the same at 50% each.

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Unit Cost:

The unit cost in the third quarter was reported at 28.82 USD/barrel; quite close to the prior guidance of 29 USD/barrel. The figure is higher than that of the second quarter by 0.03 USD/barrel, mainly from the increase in DD&A from Bongkot, S1 and Arthit, together with higher exploration expenses resulting from field withdrawal in Australia. On the other hand, with a slightly higher production volume in the third quarter of about 478 KBOED, a marginal decrease in the operating expense can be observed.

The unit cost decreased YoY from 29.39 USD/barrel in Q3/21 to 28.82 USD/barrel in Q3/22, despite a slightly lower DD&A, mainly because Oman Block 61, Bongkot and G2 have a rather low DD&A, and also due to the fact that the volume in 2021 was lower than in Q3/22. The figure as of 9M22 is largely the same with no significant differing indicators.

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Cash Flow, Financial Position

The beginning cash was reported at approximately 2.6 billion USD, with cash flows from operations of approximately 4.5 billion USD, owing to a high EBITDA margin of 76%. The amount of tax paid was about 1.3 billion USD, excluding royalty and other expenses paid to the government. CAPEX amounted to 1.2 billion USD, while dividend payment was 819 million USD, including the payment made at the beginning of the year and the interim dividend payment for this year. The ending cash as of September 2022 was approximately 3.4 billion USD. However, we have debt being settled in October to alleviate the interest burden.

The Company's total assets increased from 23,445 million USD to 24,684 million USD in Q3/22. The equity increased by approximately 600 million USD, which is not that significant, because out of the net profit of 1,581 million USD, we have dividend payout of about 800 million USD, and the perpetual bond repayment of about 500 million USD, hence the increase in equity was quite limited.

The debt-to-equity ratio still remained strong at 0.33x in the third quarter, with the average cost of debt of 3.73% and the average loan life of 12.8 years.

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Guidance, Debt Profile and Ratings

The sales volume guidance in Q4/22 is likely to increase, supported by sales volume contributions from Bongkot, G1/61 (Erawan) and Algeria Hassi Bir Rekaiz Projects, which expects the first crude load in the fourth quarter. The full-year average sales volume, therefore, expects to be approximately 468 KBOED.

In Q4/22, gas price is likely to increase to approximately 6.7 USD/MMBTU and the average gas price throughout the year has been guided to be around 6.3 USD/MMBTU.

Even though the unit cost over the past 3 quarters was still well below 29 USD/barrel, our guidance for 2022 will be in the range of 29-30 USD/barrel. EBITDA margin outlook remains unchanged at 70-75%.

PART 6: QUESTIONS & ANSWERS (Q&A)

Question # 1

What are the underlying reasons for exiting Brazil in this high oil price situation?

Answer from PTTEP's management

As part of our portfolio rationalization, Brazil is not our focus area and does not fit to our strategy. The decision made when entering to Brazil at the first place occurred when oil supply deficit, but the environment now has been completely changed and we need to consider on the balance of its risks and returns.

Question # 2

Could you please share if there are any downside risks to G1/61 ramp-up plan? Do the drilling activities progress as plan?

Answer from PTTEP's management

The drillings of G1/61 project progress as plan. Additional drilling rigs will arrive in Q4/2022. The first ramp-up stage will be able to achieve in the middle of next year.

Question # 3

Could you elaborate more on G1/61 project ramping up plan? What is the volume at the end of 2023 and which quarter of 2024 can the company ramp up to 800 mmscfd?

Answer from PTTEP's management

We are confident that 800 mmscfd will be reached in April 2024. For the ramping up step, it will have more clarity and be updated later on around the beginning of next year.

Question # 4

In order to alleviate the impact from LNG imports, has volume from the mitigation fields, e.g. Arthit and MTJDA projects in the time of G1/61 ramping up around 200 mmscfd come in or it will be started next year?

Answer from PTTEP's management

Additional volume of 200 mmscfd is our target that we try our best to reach. Currently, approximately 120 mmscfd from Arthit, Bongkot and MTJDA has already come in.

Question # 5

Is there possibility for additional Mozambique impairment this year? Has TotalEnergies decided on the site access timeline yet?

Answer from PTTEP's management

The construction on-site is delayed. We are still waiting for the situation to improve to get back into the site. TotalEnergies, the operator, has signaled the possibility for site access early next year, after the military force has taken care of the area. More clarity will be available in Q1/2023.

For impairment, we will further assess at the end of this year.

Question # 6

Please update on Lang Lebah project potential. Will it be possible for LLB as a backfield to Bintulu LNG plant in case there are gas shortage from other fields?

Answer from PTTEP's management

We expect better field potential for Lang Lebah. We are currently exploring nearby area and evaluating the result. For LLB, work is on-going for front-end engineering design (FEED) together with negotiating on commercial terms. Furthermore, we plan to drill one more well at the western area of LLB next year. The progress is expected to be as planned for FID. Moreover, we plan to develop CCS at LLB.

Question # 7

Could the company update on the new business e.g. ARV, Hydrogen? Are the target of 20% NI contribution from new business by 2030 revised?

Answer from PTTEP's management

We still expect to see 20% of NI contribution from new business. ARV is ready to scale up and expands to other businesses other than the existing four (Rovula, Skyller, Varuna and Cariva). It has already generated revenue. However, it might take time to see the positive net income.

From our strategies on diversify, other focus areas are CCUS, Hydrogen, power-to-x and other technology, which will drive to achieve the target.

Question # 8

Could you please share the gas price and cost structure for PSC projects i.e. G1/61 and G2/61 and Malaysia projects which the price seems to be 30-40% lower than in the concession regimes?

Answer from PTTEP's management

Return on PSC projects is generally weighted on the overall gas price and investment cost. . Malaysia projects are currently providing us with generous returns even at lower gas prices. For information, Malaysia gas price is currently around 4-5$/mmbtu, while Gulf of Thailand gas price is around 6$/mmbtu.

Question # 9

What is new effective tax rate guidance after the company got approved for Malaysia tax incentives?

Answer from PTTEP's management

Malaysia tax incentives in Q3/2022 was a one-off transaction so it will not impact on overall effective tax rate. Petroleum Income Tax rate in Malaysia remains the same at approximately 38% and company's guidance on effective tax rate is still in the range of 45%-50%.

Question # 10

Regarding G1/61 ramping up and cost expects to be increased, can the company negotiate with the government to share on the incremental cost since it is not the company's fault for the delay in entering to the site?

Answer from PTTEP's management

We do not have intention to re-negotiate the gas price so it will follow the GSA. G1/61 and G2/61 basically have high upfront capital cost from installing WHPs and drilling wells, so we will see high DD&A at the beginning period as the volume does not come in yet. But it is the longer-term investment since the reserves will be added in the future.

Question # 11

From the lower oil price recently, how does the company manage the profit growth since the price has decreased on the faster pace than sales volume increases?

Answer from PTTEP's management

As price is uncontrollable factor, so we rather focusing on maintaining gas producing level and managing unit cost to sustain our profit in the long run. We have CAGR in the range of 3-5%.

Question # 12

What are expected sales volume in 2023 and 2024?

Answer from PTTEP's management

Guidance on the sales volume in the next few years is rather flat, but certain projects might drive sales growth for example, LLB project sanction, 1st cargo of Mozambique LNG project and monetization of other projects that we have made discovery

To analyze company's growth and performance, we should consider on both production volume and sales volume together with unit cost. If we look at production volume, it is obviously showing growth. But in terms of sales volume, it might be rather flat since we have more portion of PSC in our portfolio, which have effect on our net sale entitlement.

Question # 13

Which projects do the sales volume growth in Q4/2022 contribute from?

Answer from PTTEP's management

The sales volume growth in Q4/2022 contributes from Bongkot and Arthit production increase, (up to 850 and 330 mmscfd respectively in October 2022), Algeria Hassi Bir Rekaiz Project (HBR) and Zawtika from drilling more wells.

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Forward-looking Information

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Petroleum Reserves and Resources Information

In this transcript, the Company discloses petroleum reserves and resources that are not included in the Securities Exchange and Commission of Thailand (SEC) Annual Registration Statement Form 56-1 under "Supplemental Information on Petroleum Exploration and Production Activities". The reserves and resources data contained in this transcript reflects the Company's best estimates of its reserves and resources. While the Company periodically obtains an independent audit of a portion of its proved reserves, no independent qualified reserves evaluator or auditor was involved in the preparation of reserves and resources data disclosed in this transcript. Unless stated otherwise, reserves and resources are stated at the Company's gross basis.

This transcript may contain the terms "proved reserves", "probable reserves", and/or "contingent resources". Unless stated otherwise, the Company adopts similar description as defined by the Society of Petroleum Engineers.

Proved Reserves - *Proved reserves are defined as those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.*

Probable Reserves - *Probable reserves are defined as those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable.*

Contingent Resources - *Contingent resources are defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable. The reasons for non-commerciality could be economic including market availability, political, environmental, or technological.*