PTTEP Q3 2023 Analyst Meeting
Edited Transcript

Venue: Microsoft Teams Meeting
27 October 2023
13:30 – 15:00 PM

Speakers:

Khun Montri Rawanchaikul
Chief Executive Officer

Khun Chayong Borisuitsawat
Executive Vice President - Strategy, Business Development and Human Resources

Khun Sumrid Sumneing
Executive Vice President - Finance and Accounting

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 2023. 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 the current status as well as the outlook for the national energy security, investment outlook in potential areas and the investment milestones for G1/61 project, natural gas capacity compensation, quarterly updates and highlights for E&P projects **2) Khun Chayong Borisuitsawat**, Executive Vice President – Strategy, Business Development and Human Resources, who will discuss the global price situation for oil and LNG market, as well as PTTEP's progress on the 3 key strategies; Drive Value, Decarbonize and Diversify **3) Khun Sumrid Sumneing**, Executive Vice President – Finance and Accounting Group, who will summarize PTTEP's performance in the third quarter of 2023, financial position, and the financial outlook for full year 2023 operating results. Without further ado, please join me in welcoming our CEO to commence the presentation.

PART 1: Business Update

Khun Montri Rawanchaikul,
Chief Executive Officer

Slide 4

Safeguarding TH Energy Security:

We have been observing the natural gas utilization in Thailand for quite some time. Natural gas domestic consumption for electricity generation and industrial consumption (as of 8 months of 2023) was approximately 4,740 MMSCFD, whereas a certain portion of gas will be transferred to the gas separation plant to convert into other petrochemical products. Out of 4,740 MMSCFD, 56% of which is from domestic production, i.e., from projects in the Gulf of Thailand, where projects such as G1/61, G2/61, Arthit, Pailin, and B8/32, that has just resumed operations, are located.

Gas supply of approximately 670 MMSCD, or 14% of country's natural gas consumption, is imported from Yadana and Zawtika projects in Myanmar via pipelines, whereby PTTEP is the operator of both projects. Some portions of the gas from these two projects are sold domestically in Myanmar and contributing as high as 50% of electricity generation in Myanmar. Hence, if there are any issues with these production sites, it will affect about 14% of the natural gas supply in Thailand and we will have to resort to LNG instead, with higher energy cost for the nation. In this regard, LNG import represents about 30% of the total volume; equivalent to 1,450 MMSCFD or about 1 million tons. (The country's LNG demand per year is approximately 10 million tons, whereby one LNG cargo carries between 50,000-70,000 tons depending on the vessel type.) This potentially impacts the pool gas price that we use for electricity generation.

Moving on to the natural gas price, the light blue line is PTTEP's price in the Gulf of Thailand, while the yellow line is TH pool price that takes into account the contractual and spot prices of imported LNG. The dark blue line represents LNG pool price, which a surge was seen last year due to an abrupt increase in the global LNG spot price. With this, please be affirmed that PTTEP is not the reason behind TH high electricity expenses and our gas production has been quite stable. Despite minor fluctuations due to the adjustment of gas price following oil price fluctuations, our gas price is still very resilient, compared to the LNG price.

It has been forecasted that Europe is going to see a severe winter this year, coupled with the prolonged geopolitical conflicts between Russia and Ukraine that could last until 2025-2026, as well as the tension in the Middle East. All of these factors could affect the LNG price, which in turn affects the pool gas price of the country. The magnitude of the impact depends on the required volume of imported LNG to meet the country's demand.

Therefore, PTTEP's objective is to ensure our gas production in the maximum amount to serve TH demand, though this can be challenging as our key producing assets in the Gulf of Thailand have been operating for several years, and it is critically important that we keep adding on new investments, for examples, G1/61 and G2/61. We are making a historical mark in a way that the number of drilling platforms in the Gulf of Thailand has reached the highest in many years, at about 12-13 platforms, and still counting.

Referring to the map on the upper right, we are operating G1/61, G2/61, Malaysia Thailand Joint Development Area (Block B17) projects in collaboration with CPOC, supplying about 30-40 MMSCFD of gas to Thailand, while the remaining 200 MMSCFD is purchased by Malaysia in accordance with the agreement. Meanwhile, Block A18 at the middle part of MTJDA supplies about 400-500 MMSCFD of gas to Thailand.

As for the Overlapping Claims Area (OCA) between Thailand and Cambodia highlighted in blue, this area has never before been properly explored. It has been speculated that this area has abundant petroleum reserves, which could be possible as it is located right next to G1/61 so the subsurface structure should be quite similar. If the agreement between two countries can be reached, we can have access to additional natural gas supply to minimize reliance on LNG, allowing us to control gas price and subsequently the Ft rate.

The key message that we would like to convey today is that we put our best effort in the mission to produce gas to safeguard Thailand's energy security, and in turn we can support fundamental well-being of the people in Myanmar by way of supplying gas for electricity generation. In the meantime, we anticipate that a mutual agreement can be reached for the OCA to take advantages of the gas supply, with close proximity of gas pipelines to Map Ta Phut area.

Slide 5

G2/61 & Arthit: Surpassing the Commitment to Bridge G1/61's Shortfall:

We put our best endeavor and is confident in delivering 800 MMSCFD of gas from G1/61 by April 2024. Looking ahead to December this year, G2/61 (formerly known as Bongkot) is committed to supplying 825 MMSCFD, matching our production capacity. However, the commitment for the first quarter of 2024 decreases to 700 MMSCFD. Fortunately, our production capacity still comfortably exceeds this commitment, allowing us to offset any shortfalls in G1/61's production, which falls slightly below the target of 800 MMSCFD. In this context, Arthit has also played a crucial role as it consistently delivers 330 MMSCFD, surpassing the commitment of 294 MMSCFD. We expect to maintain our production capacity through the first quarter of 2024.

As for G1/61, we have just sorted out a solution with the vessel access to the site and we are doing our best to ramp up production with the anticipation to achieve 800 MMSCFD by April 2024. Hence, what we are trying to do is to make up for the missing capacity at G1/61, with additional production from G2/61 and Arthit projects. All in all, we believe we can deliver what we have committed by April 2024, whereby there is a promising potential for Arthit, with additional investment in the production platforms.

Slide 6

E&P Business Update:

There have been several developments in the past quarter. We have seen G1/61's production fluctuating between 400-420 MMSCFD with the target to achieve 800 MMSCFD by April 2024. G2/61, also known as Bongkot, with its maximum daily production capacity of 860 MMSCFD, exceeding the commitment of 825 MMSCFD, while Arthit has been producing at 350 MMSCFD, surpassing the target of 294 MMSCFD.

Additionally, we have acquired 33.33% stakes of G12/48 project from Total Energies, who intended to pull out from Thailand. G12/48 is not material in production size but is of significance (located in the area of G2/61), with the capacity of about 8-9 MMSCFD.

B8/32 project is an oil field with natural gas output of approximately 50 MMSCFD. If you still recall, there was an issue with the water seeping into vessel hull at the beginning of the year. If we were to repair the vessel, it would take about 18 months to complete, so we have come up with an innovative idea to incorporate an additional vessel as a bypass, allowing production to resume by October. As a result, PTTEP has successfully resumed production of 50 MMSCFD of gas and 5,000 BOED of oil, since the beginning of October.

We have ramped up oil production at Algeria Hassi Bir Rekaiz project (HBR) from 13,000 BPD to 17,000 BPD since August 2023. Besides, we have signed a 10-year extension agreement for the LNG production project (midstream) in Oman until 2034.

Regarding projects under development, we have received a confirmation from the operator of Mozambique LNG; Total Energies, that they are working towards re-accessing the site by early 2024, with security issues now under control. Hence, we can expect the first cargo from Mozambique LNG to be shipped during the first half of 2028. The project's capacity is 12.5 million tons, and with an additional 1 million tons of spare capacity, we will have a total of 13.5 million tons available in 2028.

We were awarded the gas holding area at Lang Lebah in Malaysia at the end of 2022, meaning that we discovered the gas field and that the site is considered a producing asset. Though the front-end engineering design (FEED) was completed in October, there is a possibility of delay for this project due to difficulty of conceptual development and planning during COVID-19. Thus, it is important to make sure that it is not getting delayed further, and we need to expedite the bidding process, which consists of several components such as wellhead platforms, on-shore gas separation plants, drilling wells, and pipelines. We released the first batch of bidding invitations last week, and by the middle of 2024 we will compile bidding results to discuss commercial terms, gas price, investment potential and proceed to announce the final investment decisions. Given this, we can expect the first gas by around the same time as Mozambique in the first half of 2028. In this regard, gas from Lang Lebah will be sold on-shore to Petronas to produce LNG.

Regarding SK405B project in Malaysia, this is an exploration site located in South Sarawak, where we have discovered a few oil and gas potential in the area. We are working to expedite a tangible development plan for these fields by early 2025 to proceed with the investment decisions.

As a result of portfolio review, we have decided to surrender the Mariana Oil Sand project in Canada back to the government, which was completed in August 2023, as well as Cash Maple in Australia, where we discovered a gas field, but it is very hard to develop further as it is located approximately 800 kilometers away from the shore. As a result, we have negotiated with the operator nearby who already had the pipelines installed, ultimately reaching an agreement to divest this asset to them.

With that being said, our focus areas for the time being will be Thailand, Myanmar, Malaysia and the Middle East, specifically Oman and the UAE. For Oman, we have Block 6 and Block 61, while in the UAE we are expediting the development plan for the gas fields (currently under exploration phase), while the Algeria projects has begun to play a significant role with the addition of a new fields.

PART 2: Market & Strategy Update

Khun Chayong Borisuitsawat,
Executive Vice President – Strategy, Business Development and Human Resources

Slide 8

Market Update:

The crude oil price in the third quarter was reported at 86.6 USD/barrel, increasing QoQ due to the continued production cut extension by Saudi Arabia and Russia that could last until the first quarter of 2024, potentially allowing the crude oil price to remain stable. Moreover, there has been an emerging incident especially the unrest between Israel and Hamas. However, this incident does not really have an impact on the oil supply, but it is more of a market's reactive response. Going forward, we have to keep an eye on whether or not the situation is going to persist and to what extent it is going to escalate.

Crude oil demand is likely to subside as winter approaches, while the economic growth in many countries remains quite limited, which does not either increase or decrease crude oil demand in a significant manner. Therefore, it affirms our guidance that the crude oil price should fluctuate between 80-90 USD/barrel through to the first quarter of 2024 due to no particular indicators that may suggest otherwise. Nevertheless, factors to watch out for are the economic growth potential, production outlook for the OPEC+ and the non-OPEC producers, as well as geopolitical conflicts between Russia and Ukraine, and Israel and Hamas.

The LNG spot price increased QoQ to 12.55 USD/MMBTU, due to a slight supply depletion resulting from the labour union strike and maintenance shutdown of LNG plants in Australia. However, the accumulated LNG inventory for the winter season may be able to capture seasonal market demand. At this point, gas supply still exceeds demand, and the addition of new LNG projects is likely to increase supply going forward.

Slide 9

Drive Value for Excellence:

One of PTTEP's strategic pillars is 'Drive E&P values', focusing on expediting production and ramping up production in high potential areas, as well as improving cost synergy to drive down the unit cost.

Another focus area is to go ahead with the exploration of G1/65 and G3/65 that we have won the bidding early this year. Thailand is the major revenue contributor of PTTEP, contributing 67% of the total sales volume, affirming the potential to further expand production in this home base. Besides, we anticipate that the Overlapping Claims Area or OCA is going to complement Thailand's energy security.

The next focus area lies in Myanmar, a region that currently contributes 9% of the total sales volume. We are firmly determined to uphold our strategy to maintain production capacity, given the potential to further expand our production within our existing production fields such as Zawtika or Yadana. However, it is yet to be determined how the additional capacity will contribute to enhance the overall production capacity in Myanmar as well as the consistency of energy supply to Thailand.

The revenue contribution Malaysia accounts for about 10% of the total sales volume. We place a high expectation on Malaysia as the expansion activities have been quite intensive in the past few years. We have plans to jointly develop our assets in Malaysia into inter-connected clusters. Exploration activities have been carried out, with continuous discoveries of petroleum fields in the area. There are 12 projects in total, whereby 4 of them have already commenced production. One of them is Lang Lebah, which is now approaching the Final Investment Decision for further development. These assets will be jointly developed in clusters that can capitalize on the synergies in terms of production facilities. It is our priority to expedite revenue generation and cash inflows from all of the assets in Malaysia, which have proven to be highly important for PTTEP's future.

The fourth focus area is the Middle East, encompassing Oman and the UAE, which altogether represent about 11% of the total sales volume. There are 9 investment projects in both countries, with 3 of them being producing assets, while another 2 are mid-stream projects. There is a petroleum project in the UAE with high development potential that we are working on, while other projects are actively being explored by the experienced operators in the area. In this regard, PTTEP is the partner in these exploration projects as we are not yet the sole operator in the Middle East. However, these operators are global oil companies with the potential to ensure successful execution. All in all, our 'Drive Value' strategy is mainly going to focus on these 4 strategic regions.

Slide 10

Commitment to Decarbonization:

Decarbonization is the initiative that directly supports the petroleum business, and it is also on the global agenda. The petroleum business plays a critical role in ensuring energy security and it is our mission to produce clean energy. We have already announced our EP Net Zero target by the year 2050, with series of interim targets, focusing on the amount of greenhouse gas emissions per production, whereby the amount of carbon emissions to be reduced should increase as we have expanded our production capacity. To achieve this, there are 3 major strategies; 1) Avoid, 2) Mitigate and 3) Offset.

On 'Avoid', the emphasis is on identifying projects or investments that emit lower amount of carbon than we are currently emitting, so the carbon content to be emitted by PTTEP will decrease over time.

On 'Mitigate', we aim to lower carbon emissions from our production process. One of the important endeavors that is closely associated with the mitigation strategy is the CCS or carbon capture and storage. For instance, we have plan to implement carbon capture and storage projects at Arthit and Lang Lebah, which will be explained more in details.

On 'Offset', the focus is to absorb the carbon to compensate for the amount of carbon being emitted from our processes. Speaking of which, there are 3 carbon offset measures; carbon removal project including reforestation, community and partner collaboration where we try to engage community members to plantation of mangrove forests, community forests as well as Ocean for Life project, and lastly carbon credit portfolio management to help offset the amount of carbon being emitted.

On execution of these strategies, there are a few noteworthy milestones, for instance, an MOU with UNEP for Oil & Gas Methane Partnership in anticipation for zero methane emissions. Furthermore, the carbon capture and storage project at Arthit is now being studied in terms of front-end engineering design, technical details, investment budget and commercial potential. The 3 key elements, for a successful implementation of the CCS, are the license to operate, identification of ways to get some returns to compensate additional costs, which we are not intending to generate profits from the pilot CCS project at this point, but the focus will be on looking for potential partners or co-operators to ensure that the project is financially viable. The third element is the MMV (Measurement, Monitoring, and Verification) or liabilities, which involves discussion and negotiation with the government to ensure that the investment does not go in vain for too long. By early 2024, we should be able to reach a final investment decision of the CCS at Arthit project.

Moreover, there is a new initiative to enhance flaring efficiency in Malaysia and G2/61 projects that can potentially reduce greenhouse gas emission by 33,000 tons of CO_2 equivalent per year.

Slide 11

Diversify for the Future:

With a belief that the oil and gas industry is going to lose its importance over time, it still plays a significant role as there are no other types of energy that can fully replace conventional oil and gas rapidly enough at the moment. Despite that, PTTEP has to be prepared for future disruption, and so we continuously discuss the potential development of new businesses beyond oil and gas. The first diversification measure is the CCS as a Service, which takes knowledge and experiences in petroleum exploration and production. As certain businesses in Thailand need to reduce its carbon emission, CCS can be an effective options on a large scale. This can also bring about new business opportunities and foster collaboration with other industrial sectors or industries. We are planning to execute CCS as a service or CCS hub at the upper part of the Gulf of Thailand, through collaboration and feasibility studies with the government sector, PTT Group and external bodies. This initiative will eventually minimize carbon emissions and allow the country to achieve the Net Zero aspirations.

The next diversification strategy is to invest in low-carbon energy businesses including renewable energy, hydrogen and biofuel. PTTEP is currently studying the just-awarded green hydrogen project in Oman and it is yet to be determined whether the project is worth the investment, as well as whether the technological potential suffices to ensure the efficiency in the future.

Additionally, we have a subsidiary, namely AI and Robotics Ventures or ARV, with the objective of driving revenue generation and expanding the businesses to support growth momentum in the future. What we do in ARV are essentially going to support both the petroleum and new energy businesses.

In terms of research and development, we are continuously seeking technological support in conducting research internally, and we are also acquiring new technologies through corporate venture capitals or CVC, while at the same time ensuring that they align with our strategic direction and strategy. For instance, the Direct Air Capture or DAC features the capturing of carbon dioxide in the atmosphere. This will play an important role in the industrial sector going forward as manufacturers can ensure carbon capture within the production facilities to comply with the Carbon Border Adjustment Mechanism (CBAM) criteria and ensure that their products can be exported to certain countries. Hence, new industry players will have to implement this on-site carbon capture mechanism to minimize carbon emissions from their production processes. We are of the view that this technology is going to gain more importance in the future and will be very much in demand among the industrial community.

On the low-carbon energy businesses, our areas of interest are low-speed wind turbines, bio-fuel conversion and sustainable aviation fuel or sustainable marine fuel, whereby sea and land transportation vehicles will also have to shift to low-carbon fuel more intensively.

Finally, we aim to strengthen our E&P technologies through ARV as well as converting the carbon emitted into advanced materials such as carbon nanotube.

PART 3: Financial Results

Khun Sumrid Sumneing,
Executive Vice President – Finance and Accounting

Slide 13

Financial Results Q3/23:

The net profit as of 9M23 was USD 1,694 million and USD 514 million in Q3/23. As addressed earlier, our focus was placed upon expediting G1/61's production to achieve the 400 MMSCFD target in the middle of 2023, which was already achieved, before meeting the commitment of 800 MMSCFD by April 2024. The liquid sales volume has been rather high in the third quarter especially for the Middle East and Malaysia. Normally, when the oil inventory in storage is loaded, it can be said that the sales transaction has occurred, leading to higher liquid sales in the third quarter. Hence, the gas to liquid proportion in the third quarter was 70% and 30% respectively, which the liquid mix was extraordinary high.

It appears that the increase in our tax expense was reported due to partial write-down of Malaysia tax incentive, previously booked as Deferred Tax Asset, and after conducting a thorough review, it has come to our attention that certain items may not qualify for the originally anticipated exemption. Consequently, we have determined that a revision is necessary, resulting in the booking of a tax expense of approximately USD 33 million.

The oil price was peaked in the second quarter of 2022 at about 120 USD/barrel and has continued to decline to about 77-78 USD/barrel in the second quarter of 2023, before rising again in the third quarter. The increase in oil price is likely to affect both liquid and gas prices. Another factor to watch is the Thai Baht – US Dollar exchange rate, which was at about 33 Baht/USD before a big hike in the third quarter last year. Likewise, a similar scenario is expected in this year, with a certain degree of fluctuation, as seen from the recent depreciation of Thai Baht from 34.50 Baht/USD to about 36 Baht/USD. These figures are naturally reflected upon our sales and the overall business indicators.

The net profit decreased by about 16% QoQ from USD 610 million in Q2/23 to USD 514 million in Q3/23, despite the volume increase resulting from increased oil lifting in Malaysia and the Middle East, coupled with the recent ramping up of G1/61's capacity in the third quarter. The average selling price also increased. However, the unit cost increased by about 10% from about 26 USD/barrel in the first half of the year.

In terms of non-operating items, there are no significant items worthy of attention. Anyhow, we did incur a mark-to-market loss of USD 20 million on oil price hedging as the profit has already been booked beforehand in times when the oil price was on the rise. Meanwhile, the impact on foreign exchange or FX is not as significant as the hedging arrangements have been executed. We did record an FX gain of USD 23 million in the second quarter, primarily resulting from dividend payout.

On a year-on-year basis, Q3/23 compared to Q3/22, the average selling price decreased by about 9% following to the oil price drop, resulting in the decline in the net profit. As for non-operating items, there was an oil price hedging gain of USD 94 million in Q3/22, which was offset by the impairment loss of USD 95 million for an asset write-off in Brazil, while in Q3/23, the oil price hedging loss of USD 20 million was reported. FX activities are in line with the standard market mechanism.

Comparing 9M23 with 9M22, the net profit increased from USD 1,581 million to USD 1,694 million. There was not a significant increase in sales volume but there was a notable drop in selling price. However, one thing to note is that there was an oil price hedging loss of USD 184 million as of 9M22 following the oil price increase, coupled with the impairment loss of USD 95 million from the asset write-off in Brazil. For 9M23, the impact from oil price hedging and FX should not be that material, should the oil price be in the forecasted range and the FX does not change from its current outlook.

Slide 14

Financial Results I Volume & Price:

We reported higher production volume for Contract 4 and G1/61 projects, despite a slight decrease for G2/61 project due to a 30-day shutdown. There was also a volume increase from Malaysia project's crude oil sales, for instance, an increased volume of 10,000 BOED at Sabah K project. Likewise, there was higher oil sales in the Middle East from Oman PDO and Block 61 projects, contributing to volume increase in Q3/23, compared to Q2/23.

Looking at the performance for 9M23 compared to 9M22, the total sales volume is largely unchanged. However, there are some noteworthy differences in details. We observed a higher volume contribution from Thailand assets such as G1/61, G2/61, and Arthit projects, while other South East Asia assets' volume contribution has remained relatively stable. However, we can observe a decrease in the Middle East due to lower sales volume entitlement at Oman Block 61, according to the conditions prescribed in the Production Sharing Contract.

The volume mix between gas and liquid is 70% and 30% respectively. Liquid sales were extraordinary high due to the oil loads shifted from Q2/23 to Q3/23. The weighted average selling price increased QoQ from 45.72 USD/barrel in Q2/23 to 48.62 USD/barrel in Q3/23, with a slight decrease in gas price from 5.87 USD/MMBTU to 5.75 USD/MMBTU. Liquid price, on the other hand, increased by 11%, largely aligns with the oil price, which should mostly reflect the current market situation with the possibility of minor time lag especially the Middle East where prices often lag behind by about 2 months, all in all leading to the increased weighted average selling price for the period.

For 9M23, the weighted average selling price decreased YoY since the price in 2022 was rather high, coupled with the downward trend in both gas and liquid prices experienced in 2023.

Slide 15

Financial Results I Unit Cost:

The unit cost was recorded at about 26 USD/barrel during the first half of 2023, before increasing in the third quarter due to the investments in G1/61 to meet the committed production capacity, consequently pushing the DD&A up high.

The increased OPEX was due to a few key reasons. One of which is that Block K in Malaysia bears a rather high operating cost, together with the adjustment of decommissioning liabilities of Sabah K that was previously set too low, all in all leading to the OPEX of 7.51 USD/barrel, and the unit cost of 29.12 USD/barrel in Q3/23. However, the unit cost for 9M23 was reported at 27.23 USD/barrel, which was about the same as in 9M22. Going forward, the unit cost is likely to remain around 28-29 USD/barrel due to the DD&A situation from big investment, whereby the CAPEX has been transferred to assets, which directly affects the increase in DD&A.

Slide 16

Financial Results I Cashflows & Financial Position

The ending cash as at December 2022 year-end was about USD 3.5 billion, with the remaining cash as at the end of Q3/23 of about USD 3 billion. We also reported the similar amount of ending cash back in Q2/23, meaning that the net cash inflow and outflow in the third quarter was about the same.

The EBITDA margin for 9M23 was 74%, with cash flow from operations amounting to USD 4,467 million. The amount of tax paid was USD 1,541 million, whereby 50% of which or about USD 800 million was paid to the Thai government and the rest was for assets elsewhere such as Myanmar and Oman. The cash outflow for investment will be rather high in the third and the fourth quarters, mostly for G1/61, G2/61, Zawtika and S1 projects. The dividend payment was about USD 1 billion.

The total assets decreased slightly by about USD 450 million, mainly from the accounting adjustment after Bongkot end of concession.

There was a decrease in interest-bearing debt to USD 3.6 billion, mostly from payment for leasing obligations. The outstanding debts were about USD 2.8 billion, while the remaining debt is mostly for the rent of rigs or vessels, which are usually booked as leasing liabilities.

On the other hand, the equity increased due to the net profit of USD 1.7 billion, offset with the dividend payment of USD 1 billion, contributing to the increase in equity of about USD 600 million.

With regards to the debt profit, the debt-to-equity ratio was 0.26x, with 100% fixed interest rates.

Slide 17

Results Guidance

The sales volume projection throughout the entire 2023 was expected at 463 KBOED. For 9M23, we achieved a volume of 457 KBOED. We anticipate that the volume should increase to 478 KBOED in Q4/23, given higher sales volume from G2/61 after annual shutdown in Q2/23, coupled with the resumption of B8/32 after the successful resolution of the vessel issue, as well as volume contribution from Contract 4 and G1/61 projects.

The gas price in the third quarter was about 5.75 USD/MMBTU. In this regard, the gas price is usually reset in the fourth quarter, and this reset can be based on a reflection of oil price for the past 6-12 months or the prices from the year before. For Contract 4 and MTJDA projects, where the price adjustment lag time is 12-24 months, the price in Q4/23 will be adjusted upward to reflect the periods when oil price was relatively high. As a result, it's expected that the average gas price for full year 2023 will be around 6 USD per MMBTU.

The unit cost guidance for the whole year should be between 27-28 USD/barrel, starting off with 26 USD/barrel at the beginning of this year throughout the second quarter, and increasing to 29 USD/barrel in the third quarter. To arrive at 27-28 USD/barrel for full year, unit cost guidance for Q4/23 is anticipated to be largely similar to Q3/23.

The EBITDA margin in the third quarter stood at 74% and the full-year average will remain stable in the range of 70-75%.

And that summarizes our overall financial performance, which has already been reported to the Stock Exchange of Thailand.

PART 4: QUESTIONS & ANSWERS (Q&A)

Question # 1

For the CCS at Arthit project with expected CO_2 capacity of 700,000 tonnes of CO_2 equivalent per year (tCO_2e/year), how much is the total GHG reduction of PTTEP with and without this CCS project? Is CCS at Arthit the main contributor to the GHG intensity reduction target of at least 30% by 2030?

Answer from PTTEP's management

PTTEP has currently reduced GHG emissions approximately 700,000 – 800,000 tCO_2e/year without CCS. Total reduction will be doubling with Arthit CCS, as it provides additional reduction of 0.7 to 1 million tCO_2e/year. If this project is able to declare FID within an early next year, we expect the 1st injection around 2027-2028. In the meantime, we also aiming for CCS at Malaysia SK410B or Lang Lebah in our reduction roadmap. Thus, we believe that our first interim target, 30% intensity reduction by 2030, can be achievable.

Question # 2

Since there is still no clarity on the carbon tax, how much does an initial investment cost for CCS in comparable with CCS at overseas (e.g., Europe)?

Answer from PTTEP's management

The costs of Arthit CCS will be on two parts, the carbon capture which we already invested, and the storage costs which will be further spent, with the ballpark figures of additional 40USD/tCO_2e. Compared with the CCS cost in Europe, the investment of both capture and storage is around 100+ USD/tCO_2e. Despite the fact that we do not expect the project to be profitable, the recoverability of the cost should be at hand to make this project viable. Therefore, support from the government is also needed to be taken into consideration.

Question # 3

From CCS investment of PTTEP, will there be surplus capacity for other companies in PTT Group?

Answer from PTTEP's management

In the broader context, Thailand has GHG emissions approximately 320 million tCO_2e/year. Upstream industry like PTTEP contributes only 1-2% of the country's total emissions. If we adopt only reforestation for offsetting, without CCS, 1 million rais of forestation can reduce only about 2 million tCO_2e/year.

Considering that Thailand has an area of 320 million rais, roughly half of Thailand's land area will be dedicated to reforestation in order to offset total GHG emissions of the country, which is infeasible.

Thailand Net Zero emission target announced by the government is by 2065, with the carbon neutrality target by 2050. To achieve this, the implementation of CCS capacity of approximately 40 million tCO_2e/year is required, on top of that, other initiatives such as EVs and other offsetting measures must be taken into consideration. We also anticipate that a subsurface structure around the northern part of Gulf of Thailand, 1.4-1.6 km under sea bed, is probable for CO_2 storage, with the storage capacity of 40 million tCO_2e/year. The exploration activity will be further conducted to confirm its storage potential. For the CCS as a service project, the CO_2 emitted from PTT Group, as well as other industrial sectors around the Maptaphut area, will be transported, converted into liquid, and to be stored underground, where the pilot project at Arthit will prove that CCS is feasible in Thailand.

The development of the CCS hub is currently underway and in the discussion with the Government. We expect this project has relatively high investment cost and will require collaboration from various stakeholders, encompassing matters related to incentives to recover additional costs, as well as limitation of liabilities.

Question # 4

Are there any M&A currently under consideration? Can you share any colors on news published by Bloomberg on M&A of Renewables project in Europe, as well as gas assets in UAE?

Answer from PTTEP's management

Two types of growth can be seen from our business, which are organic growth and inorganic growth. We put an emphasis on organic growth, our existing projects in Malaysia and UAE, which are crucial in terms of strengthening the company's performance and reserves life. However, we are also open for inorganic growth opportunities, as long as it fits with our investment criteria. At present, we have a few projects in the pipeline.

Regarding the news about PTTEP's M&A, news could be considered rumors until it is officially announced by the company itself, by way of filing to the Stock Exchange of Thailand.

Question # 5

Could PTTEP comment on M&A policy regarding LNG assets? What are differences between LNG project structure in Malaysia and Mozambique?

Answer from PTTEP's management

I'd like to emphasize that, in term of strategy, PTTEP still focus on the upstream business, which is the exploration and production of petroleum, and our product is the natural gas. We do not invest purely or is directly engaged in LNG business. In Malaysia, we produce and supply natural gas to Bintulu LNG plant, for further LNG production. In contrast, in Mozambique, it is integrated E&P and LNG project. The key distinction with projects in Malaysia is that the government does not possess any LNG plants. Therefore, permits for LNG production are granted to private upstream companies to produce LNG as well. Although we do have midstream project, namely Oman LNG, where we got it as a bunch of assets back when we acquired Partex Group. Extension of the Oman LNG contract will be advantageous to us since it provides market opportunity for the potential additional gas production from Oman Block 61.

Question # 6

Regarding PTTEP's policy related to CO_2 reduction initiatives, is there any potential in the next few years to monetize those projects, while there is still no clear relevant regulatory in Thailand?

Answer from PTTEP's management

Achieving net zero GHG emissions is essential for the sustainable world. Even monetization potential of CCS in Thailand seems to be laggard at the moment, CCS is still required as it is one of the technologies that is already proven, and most likely that it will support the global net zero ambitions. Even the EV will replace ICE vehicles, the natural gas is still required for electricity generation. Therefore, we cannot avoid CCS to make our gas cleaner.

We are also exploring other technologies such as direct air capture (DAC), sustainable marine fuel (SMF), sustainable aviation fuel (SAF) and biofuel, which are the emerging trends.

In addition, the government is recently active on the climate change concerns and established the Department of Climate Change and Environment (DCCE) to accelerate on resolving the pending matters. While we might be slow, we will eventually reach our goal.

Question # 7

Are there any impact from cost increase from the oil service contracts, e.g. rig, charter?

Answer from PTTEP's management

We do not foresee short-term impact resulting from the recent hike in oil service cost, as we normally contracted for 1-3 years. However, given the substantial increase in oil service contract demand, particularly in marine, rig, and logistics, the increased in costs in next few years upon the contract renewal are foreseeable. We make our best effort to mitigate adverse impacts and maximize the benefits of those contracts.

Furthermore, we are exploring the new strategies for long-term contracts, including the possibility of linkage between service costs with the fluctuation of oil prices. Further review and discussion will be conducted and there shall be an update of our new 5-year budget in this coming December.

Question # 8

Regarding the 1st cargo delay of Mozambique LNG project from 1H2027 to 1H2028, does PTTEP expect any additional impairment charges in Q4/23?

Answer from PTTEP's management

The rule of thumb is that the entire construction period takes approximately 60 months, from the construction commencement until the first LNG cargo. Total E&P, who is the Operator of the project is quite aggressive to push this time span down to 48 months, so as to get the project online during the tight market supply situation, which will be beneficial for the project's return. The discussion among partners is ongoing and more clarity should be available by the end of this year or early next year.

The impairment assessment is normally carried out on an annual basis following accounting standard. The revised project timeline will be thoroughly considered in the impairment testing and discussion with the auditor.

Question # 9

Is there a potential increase in the dividend payout ratio?

Answer from PTTEP's management

We adhere to our dividend policy to pay dividend at least 30% of net income. Besides net income, we do include several factors into consideration, which are absolute amount per share, dividend yield, market expectation and the company's performance. During past years, the actual payout ratio of PTTEP's dividend were average at 40-50% of the net income for that period, and the dividend yield was also satisfactory compared to the market.

Question # 10

What is PTTEP's effective tax rate?

Answer from PTTEP's management

Adjusted effective tax rate of the company, taken out the one-time tax adjustment (if any) and other non-taxable income/expense, will be in the range of 40-45%.

You can reach the Investor Relations team for more information and inquiry through the following channels:

http://www.pttep.com

IR@pttep.com

+66 2 537 4000

DISCLAIMER

Forward-looking Information

The information, statements, forecasts and projections contained herein reflect the Company's current views with respect to future events and financial performance. These views are based on assumptions subject to various risks. No assurance is given that these future events will occur, or that the Company's assumptions are correct. Actual results may differ materially from those projected.

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.*