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MANAGEMENT DISCUSSION SECTION

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

Good morning and welcome to this presentation of Aker BP's fourth quarter and full year 2022. Our CFO, David Tønne, and I will hopefully provide some insight into our performance and provide updated guidance and outlook for the company. We will do this through the lens of the strategy that we presented back in July.

Let me start by sharing some perspectives on the year of 2022 for Aker BP. This was the year we completed the acquisition of Lundin Energy, the largest ever cross-border transaction done by a Norwegian company, which has roughly doubled the size of Aker BP. It took six months to complete the transaction and another three months to put in place a new organizational structure where we are all now integrated as one team. We are a stronger, more diversified, and more competent company than ever, and our asset base and opportunity set are second to none in this industry.

Another important event in 2022 was the maturation of a large set of new field development projects up to the point of final investment decision and submitting the PDOs to the authorities in December, within the deadline for the temporary tax system. This was a great achievement, and I am extremely proud of the Aker BP team and our alliance partners who have made this happen. This project will have a significant impact on the future of Aker BP.

Thirdly, the operational and financial results for 2022 were strong. This was obviously impacted by high oil and gas prices. But to me, the most important driver is the quality of operations, where we are delivering improvements on both safety, efficiency, emissions and cost. Excellence in this area is the key to reach Aker BP's rich vision, which is to be the leading company in our sector.

For our industry, there is one issue that has overshadowed everything else in 2022, and that is the European energy crisis. The geopolitical situation has created a huge shortfall of energy in the European market. And together with the rest of the Norwegian oil and gas industry, we have done what we can to help the situation. The most important initiative Aker BP took last year in this regard was to change the production strategy at Skarv as we initiated a blowdown phase for parts of the field. This contributed to a gross increase of about 2 Bcm of gas to European markets for Aker BP-operated fields. Also, on the oil side, we have increased our shipments to European buyers, replacing volumes from less favored sources.

Here are Aker BP's strategic priorities, which we presented in July following the completion of the Lundin transaction. This outlines how we are going to reach our goals. We are going to operate safely and efficiently, and we are on a journey to decarbonize our business. We have an important task ahead of us to execute on our large project portfolio, while at the same time, we continue to build new growth options for the company. And finally, we will do this in a way that maximizes the value for our shareholders and the society. We will now discuss the performance and outlook for each of them in turn.

I was once asked by a fund manager in New York, why is safety important? It is a great question. The normal answer is that it is our license to operate, but there's more to it. High safety goes hand in hand with high efficiency, hence, a strong safety record is also a good indicator of good operational performance. But most importantly, we are talking about human beings. So I told this fund manager about a lesson I learned myself many years ago from my leaders in a completely different industry, and that is never to ask people to do something you wouldn't do yourself. I still think this is a brilliant principle and I want Aker BP and our leaders to do the same.

As this chart clearly illustrates, our injury frequency has been trending down nicely through 2022, which is, of course, very good. We did, however, had three serious incidents in Q4, two of which involved falling objects. Luckily, no one was injured, but we take these matters extremely seriously and we investigate each incident to learn and to prevent it from happening again.

A key performance indicator for us is production efficiency, or PE, for short. To reach 100% on these metrics, all production-related system, it being production wells, subsea systems, topside facilities, or export pipelines must be working 100% of the time and at full capacity. Any shutdowns, planned or unplanned, will pull the PE down. According to the last McKinsey benchmark for 2021, the average PE for the Norwegian continental shelf was 87%, compared to 90% for Aker BP, including Edvard Grieg. When we defined the strategic targets for the new Aker BP, we targeted a PE of 95%, and I'm very pleased to see that we achieved this level during the second half of 2022, because this does not come easy.

It requires systematic focus on doing the right things right 24/7, and it requires that we establish and execute a timely maintenance program to ensure asset integrity. And when unexpected problems occur, which they unfortunately do from time to time, we need to be able to mobilize the right resources to fix it as quickly as we can. The high PE is the reason why we produced more than the guidance in the second half, and the increase in production from Q3 to Q4 is mainly driven by the start-up of the Johan Sverdrup Phase 2 in the middle of December, which I will come back to later.

Another important metric of operational excellence and competitiveness is, of course, cost. Our long-term target for production costs remains unchanged at $7 per barrel. And for many years, this has, in reality, been more of a mission than an actual target. But now we are here, at least if we normalize for power cost, for which we have a natural hedge through the gas price.

Going forward, keeping production costs at this level is no easy task. We are fighting against both inflationary forces and natural decline, and large part of the cost are fixed and determined by the way the production facilities are designed. The only way to counter these forces is to remain laser-focused on continuous improvement across the board and to ensure that we build new infrastructure, we optimize the design to minimize cost, not only for the development phase, but for the entire lifetime of the [ph] asset (00:07:33).

In our strategy update in July, we sharpened our focus on decarbonization, and we established a clear plan to achieve net zero emissions across our operations by 2030. The initiatives to get there can be grouped into three main categories. Firstly, we will avoid emissions wherever possible. This can be done through electrification or through portfolio optimization and asset retirement. Second, when avoidance is not realistic or prohibitively expensive, we aim to minimize emissions through more efficient use of energy on our fields and rigs. And thirdly, we intend to offset the residual emissions through reforestation or other carbon removal projects. We already have a significant exposure of this through the reforestation investments we acquired from Lundin.

When it comes to Scope 3, which are direct/indirect emissions through our value chain but outside the company, we have so far focused on the upstream part, and we manage this through our procurement processes. Carbon capture and storage, or CCS, is probably going to play a central role in the transition to a net zero world and the Norwegian continental shelf holds an enormous capacity for storage of CO_2. We, at Aker BP, are working with partners to evaluate the potential for CCS, both as a business opportunity and as a mean of reducing our net carbon footprint in the future. Now this is the strategy.

Let us turn to how we are performing. And as this chart shows, we are progressing well. In Q4, we posted the lowest emissions intensity ever for the company of 3.1 kilogram per barrel across our portfolio. Now there are three main drivers for this improvement from Q3 to Q4. The largest effect came at Edvard Grieg, which started receiving power from shore towards the end of the quarter as a part of the Johan Sverdrup Phase 2 project. The full year effect of this alone represent more than 200,000 tonnes in reduced emissions. In addition, our focus on continuous energy efficiency improvements has delivered another 70,000 tonnes of annual reductions, significantly outperforming our own targets, and these effects are also gradually being realized.

Now Q4 was also a period with lower drilling activity than normal, so that means that there is a certain element of temporary reduction in these numbers. I am very pleased with the steady progress we are making in this area. And as the cost of emissions is increasing, this is no longer just a matter of doing things right for the environment. It also has a direct effect on the bottom line. Low emissions is becoming a competitive advantage. So let us now look at how we compete in this space.

Compared to the global average, Aker BP has been a low emissions producer for many years, but it has been difficult to find good comparative data. We have now received these benchmark data from Rystad, which I believe speaks for themself, but I will say it anyway. Aker BP is among the very best and we are, of course, very pleased to be in such a good position. It is great to be in front, but it's also important for us to stay in front because the expectations to our industry are only increasing from both regulators, investors, and the society at large to solve the energy trilemma of affordable, reliable, and sustainable energy. This is why we will not relax our effort when it comes to emissions, and we have established a clear pathway to net zero.

Now this chart show exactly how we will deliver on our strategy. And as you can see, we crossed an important milestone this year. As mentioned, Edvard Grieg and Ivar Aasen are now electrified, leaving over 80% of our portfolio now powered from shore and creating a significant reduction compared to the do-nothing baseline.

Forward from here, the reductions will come from phasing out older fuel fossil assets over time in combination with continued energy efficiency measures. From 2030, we intend to offset all our emissions with reforestation and other carbon removal initiatives, and we are already well underway as the project we acquired from Lundin will cover approximately 50% of our estimated emissions from 2030 to 2040. By 2040, all our producing assets will be electrified and the residual hard to abate emissions will be low and will be neutralized for other carbon emission removal initiatives.

Delivering high return project is key for Aker BP. This is the foundation for our growth and value creation, and we have proven several times that we have got what it takes to deliver field development project on time, on cost, and with the right quality. And last year was no exception.

The Hod development achieved first oil in April, less than two years after FID. The Hod project is part of our continuous effort to increase value creation from the Valhall area, where there's more to come. The new Hod platform is built on the same blueprint and by the same people and suppliers as Valhall Flank West, just a little bit better, faster, and cheaper. We will build further on this success story in the upcoming projects.

Production also started on Phase 2 of the giant oil field, Johan Sverdrup, and this is a really important milestone for the partnership and Aker BP and lifts production capacity from 535,000 barrels per day to at least 720,000 barrels per day. And we believe this can be increased to 755,000 barrels per day when we have done the proper testing of the system. This is a truly great achievement worth celebrating and we're extremely pleased with the way Equinor has executed the project as the operator.

In addition to these very visible achievements, we also have four tie-back projects running. Three of these are in the Alvheim area and one is near Ivar Aasen. The project have a combined total reserve estimate of over 100 million barrels of oil, with excellent economics and demonstrate how we utilize existing infrastructure to develop discoveries in the vicinity of our installations.

The 16th of December was a really important day for Aker BP. On that day, we and our partners submitted a total of 10 PDOs and one PIO to the Norwegian authorities. In sum, these Aker BP-operated oil and gas projects represent one of the largest private industrial developments in Europe. Let's have a look.

[Video Presentation] (00:15:09-00:16:38)

We are really looking forward delivering these great projects together with all our partners. The scope of the development plans is a manifestation of our ambition to create the oil and gas company of the future with low cost, low emissions, profitable growth, and attractive returns. In total, we expect this project to deliver 730 million barrels of oil equivalent, net to Aker BP. They will also contribute to extending the life of existing production and enable future growth opportunities.

Along with several measures to increase efficiency and recovery, these development projects will enable Aker BP's daily production to grow from around 400,000 barrels last year to around 525,000 barrels in 2028. Aker BP will, over the next five to six years, invest $19 billion or around $19 billion [ph] pre-tax (00:17:36) in this project and we calculate an average breakeven oil price of $35 per barrel to $40 per barrel.

To further illustrate the attractiveness of these developments, we estimate an average payback time of one to two years at an oil price of $65 per barrel for the total project portfolio. Now these all look great on paper and in the spreadsheet, but we must also deliver these projects in real life. So let's now dive into the question of how we are going to deliver.

A cornerstone of our project execution strategy is our strategic alliances. This is a concept we've been working with for many years and gradually expanded to cover most of our supply chain. The alliance model provides us with a structured way to collaborate with our main suppliers over time, aiming to drive efficiency, eliminate waste, and make sure we benefit from the learning effects that come from doing the same task over and over.

The key features of the model are that we work as one team with common goals and shared incentives to do the best job possible, and it works. In fact, it works very well. Over the last six years, we have completed 16 projects under the alliance model, all with high quality, and on time, and on budget. Well, that is production started, but Hod was, in fact, one week delayed, to be honest.

And for our drilling alliances, we have drilled over 100 wells, covering some 450 kilometers of wells with industry-leading efficiency. The alliance gives us a capacity and a reach that far exceed what we would normally be possible for our company our size, and our experience so far give me great comfort with the task we have ahead of us.

As mentioned, the alliance is our cornerstone of our execution model, and our alliance partners are deeply integrated in the way we work. On this slide is the key principles of project execution in Aker BP. Now the first pillar is partnership, which is no surprise. It's all about securing capacity and competence and make sure that we internalize the effects of continuous improvement and to ensure alignment of goals and incentives.

The second pillar is what we call front-loading. A key to a successful project execution is not only the construction as such, but the preparations we've put in place before you cut the steel or spud the well. This is what lies the foundation for quality in the execution phase and the quality of the final product, and quality is the most important parameter. When this is done right, cost estimates and time schedules are much more likely to be met.

This is also the reason why we always involve our suppliers at an early stage in every project. We collaborate early with the suppliers of critical input factors to facilitate efficient engineering and mitigate late changes and we uncover interdependency between project plans to optimize the overall execution. We also spend considerable time with our alliance partners in understanding the markets, securing capacity, and developing sourcing strategies.

The third pillar of our project execution principle is standardization, which we believe is a key to driving down cost, both in development phase and in operation. And let me give you a few concrete examples. One, we will be using the same type of compressors on both Lundin, Hugin B, and Valhall PWP, with the same requirement specification and synergies and project execution, as well as in operation.

Cranes is another example where we want to standardize as much as possible to enable our remote operations and to allow for efficient maintenance in the future. And finally, we are also standardizing Christmas trees, a subsea Christmas tree that is, across Yggdrasil and the Skarv Satellites, facilitating efficient execution, providing operational flexibility and lower cost.

As I have discussed, when establishing a robust execution strategy for the parallel project, the alliance model is crucial. On this illustration, you see a breakdown of the spending on the main fields, on the CapEx side and some granularity on the contract type for the suppliers and compensation formats used to incentivize productivity.

Let me make two important points. Firstly, most of the work is performed in the alliances. For drilling and wells, our alliance partners are Noble, Odfjell Drilling and Halliburton. And one month ago, we signed a new five-year agreement for these alliances, securing all the capacity we need in the years ahead. These alliances have delivered continuous world-class performance and kept on drilling more cost efficient and better wells. Our ambition, going forward, are not any less.

For facilities, 85% of the contracted work will be performed by the fixed facilities alliance with Aker Solutions, ABB and Siemens Energy and the subsea alliance with Subsea 7 and Aker Solutions. Both these alliances have proven track record with excellent execution of previous projects.

Secondly, most of the capital spend is done through incentive-based models. For facilities and modifications, two thirds of the contract volume has incentives for productivity and cost efficiency, while Aker BP and the license partners take on the risk of procurement and cost of components.

For drilling, the commercial models are structured to incentivize high drilling performance with normal mechanism for risk management, on both up and downside. Hence, an important principle is that our partners and suppliers should only take the risk related to what they can actually control, which is their own productivity and quality and shall also have strong incentives to help Aker BP manage and optimize the entire risk exposure. We truly believe we have established a good balance.

To round off this part, I would like to point out that we have already signed contracts with jobs in Norway for most of the construction activities. On this illustration, we show what and from where the different deliveries will come and I'm very pleased we have secured this high-quality capacity at such an early stage.

In total, above 60% of the total CapEx scope will be delivered from Norway, whereas the remainder will come from global sourcing of equipment and prefabrication, amongst other, from Brazil, UK, in Asia and the Middle East.

So, we are well-prepared. We are off to a good start and for state-of-the-art partnerships and robust planning, I am very confident that we will successfully execute the program to lift our production to around 525,000 barrels per day in 2028.

Even though we have just embarked on a major CapEx program to develop fields that will give us between 250,000 and 300,000 barrels per day in 2028, we are not resting on our laurels. E&P is a long-term business and we need to have a continuous focus on adding resources to backfill our resource base.

There are basically three ways of building a resource base, exploration, increased recovery and acquisitions and we are working on all these three lines. And let me start with exploration. We remain positive to the exploration potential on the NCS and we plan to continue to be an active explorer in the years to come. We have a significant acreage position, which we are continuously renewing for licensing round and transaction.

The short version of our exploration strategy is that we focus around 80% of our efforts on opportunities near existing infrastructure. These opportunities typically have a higher chance of success. It takes shorter time and less CapEx to bring them on production and they have positive synergies with our existing assets on cost as well as asset life. The remaining 20% of the activity is directed towards opportunities with higher risk and higher reward in new play types and new geographies. We expect to be drilling 10 to 15 exploration wells per year and the goal is to find 50 million barrels on average each year.

Now, let's have a look at our exploration results last year. 2022 was a good exploration year. We discovered more than 100 million barrels, twice the target. This placed us at the top of the list in terms of net volumes discovered on the NCS. One of the main features of the exploration program was a five-well campaign in the Skarv area. The campaign resulted in two discoveries, Storjo and Newt, which we believe are commercial and which will be most likely be included in the next group of tie-back project to Skarv. We will also test the upside potential at Storjo with a new exploration well in Q4 this year.

The largest discovery was Lupa in the Barents Sea. This is a sizable gas discovery with preliminary estimates of close to 100 million barrels of oil equivalents. We would, of course, have preferred to find oil, which could have been produced through the Goliat FPSO. A gas discovery is less straightforward and will probably take longer to commercialize as it will require new gas infrastructure in the Barents Sea. But on the positive side, such discoveries are exactly what we need to unlock such infrastructure.

Today, we also present our exploration program for 2023 for the first time, built around the same strategy as before. The 2023 program consists of 17 wells, 4 of these are 2022 wells, which have been pushed into this year due to rig schedule. 15 of the 17 wells can be categorized as near-field opportunities, while Rondeslottet and Kaldafjell are in the high risk, high reward category.

Rondeslottet is actually a follow-up of a 20-year old discovery called Ellida, where the main risk is reservoir quality. The near-field opportunities are spread across different areas and play types and include several prospects in the Skarv and Yggdrasil area. We are also planning a well close to Wisting called Ferdinand. And as we announced in November, we chose to postpone the investment decision for our development of Wisting due to a combination of cost pressure, supply chain constraint and less favorable tax conditions. Our discovery at Ferdinand, in combination with further maturation of the development concept, could pave the way for a commercial Wisting development a few years down the road.

The history on the NCS has shown that big fields tend to get bigger over time and we have several great examples of this in our own portfolio with Alvheim, Skarv and Edvard Grieg and we will continue to chase the upsides in and around our existing fields. These upsides can again be split into three categories. The first category is 3P reserves, which represent upside in existing fields. We are addressing this potential with infill drilling, pressure support, et cetera, to increase recovery.

The second category is to 2C resources. These are discoveries that have not yet been through an investment decision. And when these are located within tie-back distance of one of our existing production hubs, we include them in the overall plan for that hub.

Now, finally, we have the exploration potential near existing infrastructure, also called ILX. When we make discoveries here, they become part of our 2C resources just mentioned. In sum, we actually do believe that these three categories have the potential that is roughly equal in size to our current 2P reserves.

Now, a lot of these barrels have come through exploration, but Aker BP history is not only built through organic growth. M&A has, of course, played a central role in the creation of Aker BP, with the Lundin transaction as the latest example. We don't have any really exciting news to share today, but in general, we are continually evaluating opportunities in this space.

However, we will remain true to our principles. Our focus is on quality assets with upside potential and we prefer to have the operator role. And every deal we do must be financially accretive. The ultimate goal is the same as in everything else we do, to create value which can be returned to shareholders, which brings us to the fifth strategic priority, which will be covered by our CFO, David Tønne.

David Torvik Tønne

Chief Financial Officer, Aker BP ASA

Thank you, Karl. 2022 has indeed been a transformational year for Aker BP, in many aspects, but also on the financial side. Here, we have summarized some of the key financial figures for Aker BP as we stand at the end of the fourth quarter. And having worked with the company since 2013, it is great to see what the organization has achieved together. However, the transformation and value creation journey does not stop here. Our goal is, of course, to ensure that we create at least as much value over the next 10 years as we have done the last decade. Today, I will cover two main topics. I will walk you through the fourth quarter financial performance and then I will present the latest updates to our capital allocation plan for the coming years, including specific guidance for 2023.

We start with the fourth quarter. With record high production and a small underlift, sales volume ended at 428,000 barrels of oil equivalents per day. Despite higher volumes sold, total income was down quarter-on-quarter due to lower realized prices. With almost one lifting every second day in 2022, timing of lifting is no longer that important for realized prices.

The achieved oil price for the quarter was $88.50 per barrel, very close to the average dated Brent at $89 per barrel. Most of our gas is sold on contracts linked to day-ahead prices, with roughly two-thirds going to the EU and one-third going to the UK, and our realized gas price was $150.40 per barrel of oil equivalent, in line with the observed market prices in the quarter. Combined, this gave an average hydrocarbon price of $96.50 per barrel of oil equivalents in the fourth quarter. And for the full year, realized hydrocarbon price ended at around $115 per barrel of oil equivalents.

Now moving on to production cost. Costs for the oil and gas produced was relatively stable quarter-on-quarter at $288 million. Out of the $12 million increase, $5 million are related to increased tariff and transportation expenses due to higher production. In general, maintenance activities were higher quarter-on-quarter across the assets, but costs were compensated by lower electricity prices.

The average production cost per barrel produced was $7.20 in the quarter, which means that the cost for the second half of 2022 ended in line with the guidance of roughly $7 per barrel of oil equivalents. Regarding capital spend, CapEx increased quarter-on-quarter, but still ended up at $200 million or roughly $200 million, below the updated guidance of $1.2 billion for the second half of the year.

The main drivers for the increase quarter-on-quarter was related to drilling of wells at Frosk, Ivar Aasen, and Johan Sverdrup. The underspend versus guidance is a mix of a weaker than expected Norwegian kroner, a strong cost performance on several of the projects, but also phasing of activities into 2023.

Both exploration spend and abandonment in the fourth quarter were lower than planned, as the four exploration wells, Angulata, P-Graben, Styggehøe, and Gjegnalunden, scheduled late in the fourth quarter, slipped into 2023. And the P&A work on Hod was deferred to the second quarter this year.

Now with this behind us, let's move on to look at the P&L. Total income ended at $3.8 billion. Production cost of sold volumes were up due to the higher sales volume. Still, the EBITDAX was strong at $3.5 billion, meaning a margin of over 90%. Exploration expenses was $32 million. This is lower than normal as the Lupa discovery was capitalized and four wells were moved into 2023.

Depreciation was $641 million, which corresponds to $16.10 per barrel. The accounting principle change related to abandonment provision, as described in note 1 to the financial statements, imply a higher abandonment provision due to the lower discount rates applied, which in turns, impacts the asset side and increases the depreciation.

In the quarter, we also recognized a non-cash impairment charge of $636 million, of which, around $500 million was related to the postponement of Wisting, while the remainder was technical goodwill related to Edvard Grieg. The Edvard Grieg impairment is mainly caused by lower gas forward prices at the end of the quarter compared to when the asset values and technical goodwill was recognized at fair value as part of the purchase price allocation of the Lundin acquisition. Since technical goodwill is not depreciated, but must be impaired over the lifetime of the asset, we are exposed to impairment going forward and we expect to impair technical goodwill from time to time.

Net financial costs in the quarter were $37 million compared to $174 million in the third quarter. The change is mainly by the net effect of currency losses and gains on the currency derivatives. Profit before tax then ended at $ 2.177 billion, and tax expenses amounted to $2.064 billion. The effective tax rate for the quarter was 95% and mainly driven by the impairment of goodwill without deferred tax, which increased the tax rate with roughly 14 percentage points. Consequently, net profit ended at $112 million.

As in the third quarter, we also had a change in other comprehensive income in the fourth quarter. The driver for this is that the legal entities acquired in the Lundin transaction include companies with other functional currency and dollar. This gave rise to a currency translation loss in the third quarter of $1.013 billion. In the fourth quarter, the loss was reversed by a gain of $1.308 billion. This essentially represents the net adjustment to the balance sheet, mainly as a result of the change in the dollar-NOK exchange rate for second half of 2022. Now all acquired companies have either been liquidated or merged with Aker BP. Hence, no further other comprehensive income will arise from these transactions.

The main changes in the balance sheet from the third quarter are related to the currency translation just explained. Here, parts of the balance sheet that arise from the Lundin transaction have been subject to currency adjustment due to having Norwegian kroner as a functional currency. In particular, we see this on the increase in goodwill quarter-on-quarter.

More interestingly is perhaps the key drivers for cash flow in the quarter. And although operating cash flow was very strong at $3.762 billion, the net cash flow was impacted by phasing of tax payments. First of all, since all companies on the NCS always pay two tax installments in the fourth quarter, versus one in the third, but also by the extra tax payment we chose to do in October, compensating for the higher than estimated profits in the whole of 2022, compared to when the tax installments were originally set back in June.

This means that taxes paid in the quarter was $2.955 billion, $785 million above the actual current tax for the quarter. Working capital development in the quarter was positively impacted by lower receivables and accrued income, which typically is the case when prices decline during the quarter. In addition, there is an adjustment to working capital for currency losses on NOK-denominated payables, such as tax. The working capital movement in the fourth quarter is, to a large extent, a reversal of the movements seen in the third quarter. Investment activities, excluding payments on lease debt, amounted to roughly $700 million. Dividends paid in the quarter was $332 million, and net change in cash was then minus $231 million.

Before closing out the fourth quarter and 2022, let me summarize the second half performance versus guidance on the key metrics. I have mostly covered the details already, but to sum up, operational performance in the second half was likely the best in the history of the company, and this is also reflected in the guidance metrics. Production ended above latest guidance of 410,000 to 420,000 barrels oil equivalents per day; production cost per barrel ended close to $7 at $7.20; and the total spend ended below guidance, driven by a combination of good cost control, strong delivery on ongoing projects, a weaker than expected Norwegian kroner, and phasing of activity into 2023.

Now with that behind us, it's time to shift gear and focus on what lies ahead. Those of you who have followed Aker BP in the last years will recognize this framework. My key message to you is that both our strategy and capital allocation priorities stand firm. We believe a key attribute of the E&P company of the future is a robust balance sheet with financial flexibility and investment-grade credit rating. We will invest in high return projects with low breakeven that not only arrest underlying decline but provide profitable growth. We firmly believe this is how you create sustainable shareholder value as an E&P company. And lastly, the value we create will be distributed to our stakeholders.

We start with a few comments on the financial position. We have used 2022 to build further robustness for the years to come. The Lundin acquisition supported this by providing low cost production, adding significant cash flow, and additional financial capacity. In the second quarter, we also deliberately chose to finance the $2.2 billion consideration of the acquisition from cash rather than issuing additional debt. As a result, we got credit rating upgrades from the three main rating agency in 2022, and we ended the year with a leverage ratio of 0.2, $2.8 billion in cash, and an undrawn bank facility of $3.4 billion. Now looking ahead, as we have a diversified bond portfolio with no maturities before 2025, we have a lot of flexibility with no immediate need to refinance and can take our time to extend maturities over the coming years.

Our strong financial capacity is the foundation for our ability to invest in high return projects. And today, we have talked about the project portfolio that we sanctioned during 2022. This is a diversified portfolio of highly profitable projects that will grow our production of low cost, low carbon barrels over the next five years. The project portfolio has an average unlevered IRR around 25% at $65 Brent. The average payback time from first oil is between one and two years and the estimated average breakeven at final investment decision stood between $35 and $40 per barrel, using a 10% discount rate.

We believe this to be a very attractive portfolio to invest in. At the same time, we recognize that the breakevens are higher than our target of $30 per barrel that we set when the temporary fiscal regime was put in place back in 2020. A key driver for the increase in breakevens is the adjustment to the temporary regime that the government approved in December. In addition, global cost inflation also impact our projects, and we of course have reflected this in our forecast for the coming years when sanctioning the projects. And as communicated in November, these were also the same reasons why the Wisting partnership agreed to postpone the final investment decision to 2026. To me, this was an example of responsible capital allocation and capital discipline in practice.

As we now ramp-up the project execution phase on the projects that we actually have sanctioned, we also expect to increase capital investments. And on this slide, you see our latest long-term CapEx estimate. The estimates are aligned with the CapEx figures communicated as part of our press release when we sanctioned the PDO projects in December last year. The total investment illustrated here is around $23 billion to $24 billion, where roughly $20 billion of these are related to sanctioned projects covered under the temporary fiscal regime. Approximately $19 billion of these were sanctioned in December, while the rest is related to PDO projects in the Alvheim area sanctioned earlier.

The other $3 billion to $4 billion are estimates for CapEx related to producing assets, typically drilling of new wells and other non-sanctioned projects. Note that we have not included any CapEx related to the Wisting project after a potential FID in 2026 as the project is currently being reworked with the ambition of reducing costs significantly. This means that roughly 85% of the CapEx seen on the graph, to the left, are covered by the temporary tax rules and is eligible for 81.7% tax deduction in the year it is spent, while the remaining 5.2% are deductions covered the next five years.

In total, the tax deduction for investments under this regime is 86.9%, which can be compared to a tax on profit of 78%. The consequence of this is that looking at pre-tax CapEx alone for companies operating on the Norwegian continental shelf does not make any sense, as the actual free cash flow effect is so heavily impacted by which tax regime the investments fall under. The total CapEx after tax deductions related to the investment program is estimated to less than $4 billion over the next six years, and the phasing is illustrated in the graph in the middle. This means that the actual net free cash flow impact of the investment program is less than $1 billion each year.

For comparison, Aker BP had a financial capacity of $6.2 billion, including $2.8 billion in cash on account at the of 2022. The last element in our capital frame is how we plan to return the value created. The sources and uses graph on the left hand side of this slide is familiar to many of you. We have now updated this with our latest plan data and move one year forward, leaving behind us a very strong 2022.

On the bar to the left, we show the estimated cash flow from operations after tax from 2023 to 2028 at various oil prices. Here, you see the strong underlying cash flow generation from our low cost asset base. This is then compared to the planned uses of this cash flow. The high pre-tax investment program has a significant less after tax impact, around $5.5 billion after tax are spent on investments and financing over the next six years, which is covered by organic cash flow at an oil price around $35 per barrel on average over the next six years.

Any cash flow above this is capacity for dividends and debt repayment. This cash flow generation provides a capacity for a resilient dividend that grows in line with value creation, and a key principle for Aker BP is that dividends shall reflect the financial capacity through the cycle considering the long-term financial outlook and the credit profile of the company. Our ambition is to grow the dividend by at least 5% per year over the coming investment cycle.

For 2023, the Board of Directors has proposed to pay a cash dividend of $2.20 per share. This is up 10% from 2022. The dividend is to be paid in four quarterly installments, with the next payment already in February. In addition to the proposed dividend, the guidance on other key metrics for 2023 are as follows. Production for the second half of 2022 ended at 422,000 barrels per day and we expect to grow this to between 430,000 to 460,000 barrels per day for the full year 2023. Roughly 13% of the volume is expected to be gas, while the rest is liquids.

The production is expected to ramp-up in the first months of 2023, as Johan Sverdrup Phase 2 first came on stream in late fourth quarter. Production through the year is expected to be relatively stable, but with some planned summer maintenance downtime in the late second quarter and the third quarter. Production cost for the second half of 2022 ended at $7.20 per barrel. We continue to see pressure and high volatility in key drivers for this metric. This includes general inflation and fluctuating electricity prices, CO_2 prices, and FX rates.

Given this uncertainty, we have for 2023 estimated the production cost somewhere between $7 and $8 per barrel of oil equivalents. This assumes a dollar-NOK foreign exchange rate of NOK 9.50, which is slightly stronger than what we had in 2022. Given the increasing share of electrified fields, the electricity price is an increasingly important factor for the cost per barrel metric. However, as we are a producer of natural gas, we have an intrinsic hedge and are typically more than compensated for any increase in electricity cost with the increased cash flow from our gas sales.

On CapEx, we expect to spend $3 billion to $3.5 billion in 2023. This is in line with the spend profiles of the PDO projects sanctioned in December and taking into account that some of the $200 million underspend in 2022 is phased into 2023. As the projects are now moving into execution, with final contracts being signed and payment schedules being matured, there's still quite some uncertainty regarding the in-year phasing and the between-the-year phasing of the spend. This is something that we will continue to detail over the next six to nine months and some changes should be expected.

On exploration, we plan to spend between $400 million and $500 million pre-tax. This is in line with the targeted spend per year after high-grading the exploration activity, following the integration with Lundin. The 2023 program is expected between 15 and 20 wells. The number is higher than what we typically would target because of the four wells that were deferred from 2022 into 2023. As the current drilling schedule stand, we expect similar activity in the first and the second quarter, with a slowdown in the third quarter, and then the highest level in the fourth quarter.

On abandonment, total spend is planned between $100 million and $200 million pre-tax, with almost all of the spend being linked to P&A activity on Valhall. And then lastly, on tax, as normal, we now have a fairly good overview of the total tax to be paid for the fiscal year 2022, with the last three tax installments to be paid in February, April, and June now being fixed. In addition, we have estimated the first three tax installments for the fiscal year 2023 to be paid in the second half of the year. The latter estimates are, of course, very sensitive to commodity prices, but also other metrics that we have guided on today.

For simplicity, we have in the scenario, shown here on the slide, chosen to fix the gas price at $25 per mmbtu and the dollar-NOK exchange rate at NOK 9.50. So, before leaving the word back to Karl for some concluding remarks and Q&A, let me just sum up the key messages from my presentation.

2022 has not only been another transformational year for Aker BP, but also a year with very strong operational performance. This is reflected both in our financial performance and the financial position at the end of the year, which has never been more robust. Now looking forward, with our large base of low cost, low carbon production, and investments in high return projects, our goal is to maximize long-term value creation for our shareholders and distribute this through a resilient and growing dividend.

Karl Johnny Hersvik

Chief Executive Officer, Aker BP ASA

Thank you for that, David. And before we open up for Q&A, let me quickly summarize the key messages today. Safe and efficient operations is our priority number one and I'm very pleased to see the progress on both safety, production efficiency and OpEx through 2022.

On de-carbonization, our net zero ambition by 2030 remains firm. And with the lowest emission intensity in the industry, we have a great starting point. We are going to execute a large portfolio of field development project in the years to come and we are focusing on strong partnerships, front-loading and standardization to ensure smooth execution and that we deliver the project on time and on cost and with the right quality.

2022 was a good exploration year and we continue along the same path in 2023. And finally, our financial priorities remain firm. And for 2023, we are increasing the dividends by 10%.

We will now make a short break before we open the Q&A sessions. And if you want to ask questions, please connect with the Teams link provided below on the webpage. However, if you just want to listen in, please stay right where you are and we'll be back here in around two minutes.

[Break] (00:56:34-00:58:34)

QUESTION AND ANSWER SECTION

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

So, welcome back to Q&A. And for those of you who want to ask question, which I assume is quite a few, you have logged into Teams, please raise your digital hand and Kjetil Bakken will help me to take these questions and make sure that we conduct this Q&A in an orderly fashion.

So, Kjetil, what is the first question?

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

Yes. The first question today comes from Teodor Nilsen. Teodor, please unmute and go ahead.

Teodor Sveen-Nilsen
Analyst, SpareBank 1 Markets AS
Q

Thanks for taking my questions. I have three questions. First, on electrification, you've talked about your de-carbonization strategy and then it's, of course, important with electrification. Could you talk a little bit about the economics for electrification, what will be CapEx and what will be the specific cost savings for such projects?

Second question, on production guidance for 2023, what's the implied production for Sverdrup and Valhall included in your 430,000 to 460,000 guidance?

And my last question is on cost inflation. Karl, at the third quarter presentation, you said that you break down cost inflation in [ph] 60 (00:59:51) different categories. Just wondering what has the development been for cost inflation in those categories the past quarter or if there's been any material changes? Thanks.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Thank you, Teodor. Excellent questions. When it comes to electrification, the assumption we're making when we're making these decisions is that the CO_2 cost will continue to rise and we assume that the CO_2 cost will meet the previously announced target of NOK 2,000 per tonne. And I can assure you that we actually only do NPV-positive investments in electrification to this date.

Now that is, of course – the balance is, of course, as you imply in your question, between the CapEx of actually investing it, but there was also quite a lot of savings related to maintenance cost and other issues. So, the economy is a bit balanced. So, it doesn't necessarily have to be 100% the direct CO_2 cost or the cost savings from lower CO_2 emissions.

I think it would be fair to assume that there is maybe up to NOK 500 to NOK 1,000 in addition to the direct CO2 cost savings when we do these calculations. They vary, of course, greatly from project to project, but I can assure you, we do NPV-positive investments in this case as well.

Now, the production guidance, we don't guide on fields on a standalone basis and the guidance today provided include our best estimates for production, both from Johan Sverdrup and from Edvard Grieg. And I, of course, take into account both upsides and downside in these two fields.

And then, your final question and remind me, that was...

Teodor Sveen-Nilsen
Analyst, SpareBank 1 Markets AS
Q

Cost inflation.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

...cost inflation. Okay. Excellent. Well, let's go back to DG2. I think it's worthwhile saying that, as we progress towards DG3, there has been a little bit of a trend change. So, certain components that has a global market like steel and some other material components are actually seeing a reduction in [ph] prognosed (01:02:20) inflation the next couple of years, while others, more Norwegian-specific, are pretty flat compared to the assessment we made back in the summer. So, I would say the overall trend is that the inflation pressure is somewhat reduced, but not significantly.

Teodor Sveen-Nilsen
Analyst, SpareBank 1 Markets AS
Q

Thank you. Just a follow-up on the electrification. Would you dare to provide then any payback times for electrification projects? I understand there's a wide range there, of course.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

No. We haven't provided that, but they will vary, of course. But some of these project, the most capital intensive ones, you should assume payback in the same range as, I would say, normal oil and gas investments.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

And if I may add to that, Teodor, so currently, there are not planned any big CapEx electrification projects on our fields, right. So, we have that behind us with now Edvard Grieg being electrified and Ivar Aasen being electrified as part of the Sverdrup Phase 2. Now, we are in the process where we're continuously investing in energy efficiency initiatives, which are typically much less CapEx intensive, right.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Yeah. And also have a direct impact on OpEx in terms of OpEx reduction.

Teodor Sveen-Nilsen
Analyst, SpareBank 1 Markets AS
Q

Okay. Thank you.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

A

All right. The next question is from John Olaisen from ABG. John, please unmute and go ahead.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA

Q

Hey. Good morning, ladies and gentlemen. May I ask [audio gap] (01:03:59)

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

I think we lost you, John. I can't – certainly not hear you.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

A

I'm sorry. We lost John. We'll let him back in later. Let's move on to Mark Wilson from Jefferies. Go ahead, please.

Mark Wilson
Analyst, Jefferies International Ltd.

Q

Hi. Thank you. Good morning, gents. I'd like to ask about the CapEx out to 2028 and the $3 billion to $4 billion you spoke about on, it sounds like already producing assets. It sounds like that has potentially doubled since what you spoke about in July. So, could we speak about what that actually relates to, please? Could you confirm that $19 billion for the new projects is still the same? That's the first question.

Second one is we have some people slightly surprised on the midpoint of production guidance for 2023 versus where you were in the second half of last year given Johan Sverdrup Phase 2 is on stream. So could you just give us the bridge to that guidance, and frankly, where you would be seeing declines as much as production going up? Thank you.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Thank you, Mark. So I'll do the first on CapEx, Tønne, if that's okay with you. So just to recap, right, so we are talking about a total CapEx program now that we've guided on between $23 billion and $24 billion in total. Out of that, roughly $20 billion is related to the PDO projects, sanctioned either in December last year or previously, so roughly $19 billion related to the projects sanctioned in December.

And then there is additional CapEx, as you mentioned, which we have included in the plan, which is typically infill drilling related to the existing assets, and there's also new projects that are currently sitting in our contingent resource hopper. And so we have previously talked about potential new projects in the Alvheim area. We have talked about potential new projects, which are non-operated. If you remember back, we had the [indiscernible] (01:06:20) project as well, which is a partner-operated project. So these are the additional $3 billion to $4 billion that we have currently in our plan.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

And then with respect to production guidance, there are, of course, quite a lot of pluses and minuses when we make up the assessment here. And I don't think I'll kind of provide a very specific bridge between the assessment we have today and the assessment we had in the summer. But obviously, there are some changes and one of those specific changes is the slight reduction in or decline on Alvheim, which will be offset by the Frosk coming onstream. And then there, of course, are uncertainty related to the final production volume coming out of Johan Sverdrup on Phase 2. So I think those are the kind of key issues that make up the range.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

And I guess just want to add to that as well, right. So when we presented back in July our update, we had a different starting point for our Phase 2. So, of course, with Phase 2 on Sverdrup starting up in late December, we're still in a ramp-up phase which, of course, impact then the discrete production number for our 2023.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

So it's basically a phasing discussion, right, compared to what we assumed in terms of the start-up of Johan Sverdrup.

Mark Wilson
Analyst, Jefferies International Ltd.
Q

Got it. Okay. Thank you. Very clear. I'll hand it over now. Thank you.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

All right then. We will try with John Olaisen again. Hopefully, it works now.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA
Q

Yeah. I hope you can hear me now. Sorry, I don't know what happened. I logged out and in again. So, hopefully, you can hear me now. Can you just confirm that you hear me, please, just to make sure?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Excellent, John. We're hearing you.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA
Q

Yeah. Very, very good. Your production portfolio is oil-heavy, and both you and Lundin have historically seemed to prefer oil versus gas projects. Wondering a little bit now about your 2023 exploration program. I love the table that you're providing with the detailed plan. But is it possible to give some indication of whether you're targeting oil and gas prospects in general for exploration in 2023, please?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah. So I think my feedback to the team is explore for hydrocarbons because the biggest, the most complex issue in exploration is actually to distinguish between these different phases. That being said, the 2023 program is largely focused on ILX. And since most of our hubs are in oil-heavy regions, you should assume that a significant part of the 2023 program is also oil-heavy. And the one deviation, of course, being the exploration wells close to Skarv in that gas portfolio. And then the discussion is how will the oil and gas balance be going forward? I think if you look at the award we had in the recent up around, I think our view is that the Norwegian continental shelf is still a prolific exploration region and we are probably not – we're probably more agnostic, I would say, to oil versus gas now than we have been in the past.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA

Q

Is that because of the gas price developments or anything else that has changed, if I may ask?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

It's a little related both to gas price development, but also how we view gas price outlook. And then it is also fundamentally how we think about exploration on the Norwegian continental shelf and remaining volumes.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA

Q

Makes sense. And may I ask, do you still see M&A potential on the Norwegian shelf going forward, both in the company M&A and also asset transactions, that you're likely to participate in asset transactions in 2023?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

We're doing asset transaction pretty much all the time on minor portfolio adjustments. The question, do I still see M&A potential on the Norwegian continental shelf? Yeah, the answer is yes.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA

Q

My final question, could you update us on your hedging strategy and whether there's any change to that and maybe on your hedging positions for 2023, please? That was my last question. Thank you.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. So in terms of the hedging policy, we have typically in the past used put options on oil. There's no change in the policy, but currently, we do not have any commodity hedges in place for 2023, and the reason for that is the volatility in the market. It's linked to, of course, the increased size of Aker BP and the sort of need to hedge downside risk or need to not hedge downside risk. And then the last one also is related to the tax system and the change, right. So when you don't carry forward tax losses anymore, the rationale for hedging using put options is not necessarily the same anymore.

John A. S. Olaisen
Analyst, ABG Sundal Collier Holding ASA
Q

Makes sense. Thank you very much.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

Thank you, John. And also thank you for showing your face on camera. And we would like to everyone to do that, if possible, please. Next question comes from Matt Smith of Bank of America. Go ahead, Matt. I think you need to unmute your microphone.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

Sorry, Matt. We can't hear you. So maybe you're on mute or something wrong with the connection. You might have to call John to get some tips.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

Okay.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

I think we go to the next one and try to get Matt back online.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

Let's move to the next one, which is Anish Kapadia. Please go ahead.

Anish Kapadia
Analyst, Palissy Advisors Limited
Q

Yeah. Good morning. Thanks for the presentation. Anish Kapadia here from Palissy Advisors. I had a few questions, please. I wanted to start on Wisting first of all. So it's a project that's been around for a long time. Only just over a year ago, Lundin came in and bought an additional stake for over $300 million. And you mentioned kind of going back to rework the projects and getting costs down. But from my understanding, that's already happened once in 2020-2021. And then plus last year, you had the additional tax advantages. So I'm just really trying to understand how going forward kind of three, four years, you think that you could improve this project, why it would be better delaying it for that period of time?

And then my second question was looking at your existing production base now. It seems like you've got fairly steep decline on that existing production base out to the 2027-2028 that you show on the chart. Could you just break down a bit kind of the key components of the decline by the various fields? And if you can, what is Johan Sverdrup within that?

And then just one final question on the cash flow estimates for this year. I see there was a note that you – within the kind of the wider cash flow out for the next five years, you're assuming your base case is $85 for cash flow for 2023. Can you just outline what's that expectation in terms of cash flow in that $85 scenario? Thank you.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Excellent. So let me start with Wisting. As you, of course, are aware, we postponed the investment decision towards the back end of last year, which was a result of, I would say, multiple changes, cost increase, we had price developments, we had some constraints in the supply market, we had a bit of reduction in the base reserves related to technical issues, and then finally we had some changes in the tax system. Now going forward, I think the approach to Wisting is actually threefold. So the operator is working on reducing the cost, basically changing the concept, and optimizing that concept. They are working on the technical field development, including wells, to make sure that we get back to the reserve levels we have at DG2. And then Aker BP will be operating exploration wells to increase volumes in the area, the first one to be drilled is the Ferdinand well in Q4. And in sum, at least from an ambition level, that should bring Wisting to an investable level in terms of breakeven. And then of course, we'll have to come back to the actual results as they develop.

In terms of decline, yes, there are, of course, natural decline in all of our existing fields, which we are, to a certain degree, offsetting as we go along. There was a question a bit earlier today about investments in, other investments than the $19 billion in new PDOs, which are largely tie-ins, new IOR wells, which will, to a certain degree, offset this mechanism back to 2027. We don't necessarily provide a guidance on field-to-field breakdown on decline, but I think it's fair to say that, yeah, there are some pluses and minuses. One specific thing, as you look at the long-term project or long-term profile, is that we have actually postponed the start-up of the Skarv SSP from 2026 to 2027, which might seem as a decline in terms of the production, but it's actually just to postpone the start-up. That is done for two reasons. The first one is, of course, to optimize the position under the current tax regime, but it's also due to modification scope necessary on the Skarv field.

And then you might touch on the cash flow, David.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah, yeah. No, I can definitely do that. So, I guess, you're referring to the sources and uses graph that we have on page 44 in the presentation, right. And that's an illustration of the total cash flow capacity generation over the period. And you're referring to sort of the assumption of having $85 in 2023 as the base case assumption. So one of the key reasons for doing that, when we're doing this calculation, is that we need to accommodate for the fact that taxes are phased when you pay that on the Norwegian continental shelf. So you have a tax overhang with us from a very strong 2022 into 2023. So that needs to be accounted for when we are sort of making an analysis of what the company would look like in a $40 scenario. This does not mean necessarily that $85 is our base case when we are doing our internal cash flow forecasting, and we are not guiding on cash flow at the various oil prices in specific years. So I'm afraid you have to do that calculation for yourself.

Anish Kapadia
Analyst, Palissy Advisors Limited

Q

Okay. Thank you.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Okay. Should we try to go back to Matt, Kjetil?

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

He has not currently raised his hand.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Okay.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

If he does, I will give him priority. But the next one in line is Sasi Chilukuru from Morgan Stanley. So, Sasi, please go ahead.

Sasikanth Chilukuru
Analyst, Morgan Stanley & Co. International Plc
Q

Hi. Thanks for taking my questions. I just wanted to get your view on asset disposals. You are looking at investing in growth projects. Just wondering if there are any assets in the portfolio that you would like perhaps like to exit or even reduce your stake?

Then the second question was related to FIDs. Just wondering if you could highlight how many FIDs are planned for 2023 or perhaps into 2024. And you highlighted potential projects, Alvheim and all that, was just wondering how much or how many of them will kind of come into this phase in this year?

And sorry, if I missed this and if you have already highlighted this, was just wondering what your assumptions for gas prices were in your sources and uses of cash flows like? You highlighted $25 mmbtu in 2023, just wanted to check what the assumptions were for 2024 onwards?

And sorry, one last very small one. If you could isolate the proportion of electricity costs within your OpEx guidance of $7 to $8 per BOE. Thanks.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Yeah. So let me start with asset disposal. I'm of course not going to touch into any stuff that's ongoing in terms of portfolio optimization. But I think it's fair to assume that Aker BP will engage in portfolio optimization, both on the buy side and possibly also on the sell side. And we'll come back to that when and if it happens. When it comes to the FID, if memory serves me right, I think we have four new well decisions coming up in this year, but let me get back to you concretely on that, but it's in that range.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

To add to that, there's no PDO submissions planned in 2023.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

So these are all inside already license area and ongoing projects and/or ongoing production.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

Shall I do gas price and electricity cost?

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Yeah, if you like to.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

Yes, I can do that. It's simple to answer the question. So we use 13.8% in dollar mmbtu terms and ratio to the oil price in [ph] BUA (01:20:43) terms. So we use that for each of the different scenarios in the sources and uses graph. And then on electricity cost, it's between $1 and $1.50 per barrel. And of course, electricity prices has been extremely volatile in tandem with the gas price, right. And that's also, of course, a driver then of the range on the production cost per barrel.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

So this is the reason that the range on the OpEx per barrel is what it is because after the electrification of Edvard Grieg and Ivar Aasen, now 80% of our production is actually powered from shore. So it's a surprisingly high sensitivity to electricity prices in the OpEx per barrel. If you look at the remaining part of the OpEx, that's actually been trending down quite nicely. So the background OpEx is actually trending down pretty nicely from 2021 to 2023 and we also expect the same to happen in 2023, but the big uncertain, of course, is the electricity price.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

And I, of course, don't want to repeat myself too many times, but I don't think we can talk about electricity prices without talking about revenues from gas sales, right, which is, of course, the natural hedge for that so...

Sasikanth Chilukuru
Analyst, Morgan Stanley & Co. International Plc
Q

Okay. Thank you.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

All right. Then the next question comes from Russell Searancke. Please go ahead, from Upstream Online.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

We can't hear you, Russ. Sorry, if you're muted, please unmute.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA
A

Okay. Then we'll move on to the next, which is Chris Wheaton. Chris, please go ahead.

Christopher Wheaton
Analyst, Stifel Nicolaus Europe Ltd.

Q

Thanks. Good morning, guys. Thank you very much indeed for your time this morning. Three questions from me, if I may. Firstly, going back to Mark's question on bridging the production guidance, you said you gave initial guidance for 2023 of 475,000 barrels a day post the Lundin transaction, which seems a long time ago now. But I'm interested, can you help me understand more where that – give me any help about where that bridge is between where you are today, that 445,000 barrels a day midpoint and that 475,000 barrels a day you gave a year ago. I noticed Sverdrup seems to be a big chunk of it. Is there anything particular other than that?

My second question was on tax and the guidance you've given here, David, presumably includes the cash payments, include the effect of prepaying that tax that you did in October. You've deducted that from the guidance you've given today. So we shouldn't double count that.

And my last question was on slide 22, the alliance model. Given all sanctions of projects, all the Norwegian yards, and you said 60% of your CapEx is going into Norway, all the Norwegian yards are going to be absolutely flat out, and it's really interesting to see the massive cost overrun on the Balder X Project, which actually is shown on slide 23, the Var Energi 50% cost overrun at $1.2 billion, $1.3 billion. But yet all of that cost for you is insulated because of the tax system, what matters to you much more is time. If a project is delayed, that's a much bigger hit to NPV for you. How are you thinking about, therefore, the alignment, because productivity and costs are linked [Technical Difficulty] (01:24:29) yards going to have to bear some of that cost. How do you – the cost to you is a lot lower than that is to the yard. So this feels to be a mismatch there. I'm interested, Karl Johnny, if you could talk about that, please.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah, absolutely. Three great questions, Chris. I think the easy way to talk about the change in production guidance is that back in, let's say, summer last year, we had a certain assumption of start-up on Johan Sverdrup, which of course unfortunately was a bit more aggressive than what happens in reality, which means that we should have been further progressed in the ramp-up and capacity testing. And then, of course, when then this moves to the right, the average volume in 2023 also decreases compared to what it was back in the summer of 2022, but that's the major change. And then there are quite a few other pluses and minuses, but they are in the range of 1.5% to 2%, right. And so inside, what I would call a statistic significance and hard to predict, so that's how I would think about it, if I were you, Chris. And then that doesn't mean we don't believe in Johan Sverdrup. It just means that we were a bit too aggressive back in the summer and we're still following the same ramp-up plan, but now pushed a bit to the right.

Would you like to talk about tax, David? That's your favorite subject.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah, and I can do it very, very quickly, Chris. So, yes, you are correct in assuming that the additional one-off payment that we did in October is now sort of baked in to the estimates for the first half of 2023. So we don't expect any sort of additional payments. So this is our best estimates on the tax payments in the first and in the second quarter this year, yeah.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

And then moving back to the alliance model and your discussion on time versus cost, and I'd probably throw in quality as well in that debate. So, first, let me start with this discussion around the [indiscernible] (01:26:30) project at Rosenberg, which they, of course, can comment on themself, but that is a brownfield project. They're not directly co-relatable to what we're doing in greenfield. So I think that's probably point number one, right.

And then I think that the key issue to actually deliver on time is to make sure that we have the right resources, that the plants are well-known and well worked out, that there is a link between the site need for equipment and packages, and the construction sequence on these yards. And this is where the alliance model actually excel because it means that the actual construction and, say, the major package vendors have actually been a part of developing the concept and the solutions and, therefore, have bought into the plan and are familiar with the plan. That means that as we're now progressing into detailed engineering and ultimately into construction, there are no surprises to these yards in terms of what they're supposed to deliver and when they are supposed to deliver it.

So I think we are in a lot better position than we would have been using a normal EPC contract mechanisms. And then, of course, you're absolutely right. The two key issues we are focusing on at the moment is quality, and because quality, if you deliver on quality, usually means that you deliver on time and on cost as well. And then of course, we are preoccupied also with making sure that the plans we have are linked to the real reality on these sites. And I can assure you that there's quite a lot of work ongoing at the moment and there are no red flags as far as I can see at this point in time.

Christopher Wheaton
Analyst, Stifel Nicolaus Europe Ltd.

Q

That's great. Thank you very much indeed. Thank you.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

A

All right. Then, the next question comes from Yoann Charenton of Société Générale. Please go ahead, Yoann.

Yoann Charenton
Analyst, Société Générale SA (UK)

Q

Good morning, everyone. Thank you for the presentation this morning. I will have two questions if I may. So, one is on CapEx first. CapEx-induced tax deductions have been revised on a few times in recent years. And as you explain, the last change to the temporary tax system had a significant impact on your projected breakeven levels. With this in mind, can you please help us understand how much of CapEx under your budget falls under the temporary tax system this year and next? Will you tend to say, overall, the CapEx budget is slightly backend loaded in terms of how much falls under that temporary tax system throughout the 2023, 2028 period?

And also, still on CapEx, are you able provide some high-level breakdown for this year, if possible, please, and what is the USD-NOK assumption throughout the periods that you are using with your projections?

Then, the second sort of group of question will be related to production. Last time, you provided some detailed color on production profiles for each operated hub, whereas, I think, back with the 2021 CMU, if I'm not mistaken, at the same time, the overall production outlook has been revised on a few times since then for various reasons. And so, again, with this in mind, can you please update us on Valhall, which still remains a significant contributor?

I understand that we ended some 15 KBD short of the 2022 level that was sort of projected according to that last provided illustrative profile. The same profile points to a big north of 65 KBD this year for Valhall net to Aker BP.

How close do you expect to be to that peak this year? Is that still expected? Basically, if you think about Valhall overall as a hub, is that still expected to reach its peak contribution this year based on your current plan? That would be great if you could provide any color on these two questions.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Okay. Do you want to start with the CapEx and tax and USDs and I'd do production?

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

Yeah. I can definitely do that, Yoann. So, we have communicated that roughly 85% of the CapEx under our profile is linked to the temporary tax regime or falls under the temporary tax regime. We have not split that on a year-by-year basis. And as I said in my presentation as well, we are still working on in-year phasing and also between-the-year phasing. So, we don't have a specific number on that.

But I think as you see on our CapEx ramp-up profile, you can, of course, see that we are increasing CapEx in 2025, 2026, in particular, and that would then be related and specific to Yggdrasil and PWP-Fenris and then we're leaving behind us CapEx, for example, related to Johan Sverdrup Phase 2 and so on, right. So, I think there is a probably an increase in the CapEx that falls under the temporary regime in that period.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

And then, a decrease towards the backend on the [ph] profit (01:31:50).

David Torvik Tønne
Chief Financial Officer, Aker BP ASA
A

Exactly, exactly. And then when it comes to foreign exchange assumptions, we have an FX assumption of NOK 9.50 in 2023 and then maybe use the flat rate of NOK 8.50 in the period forward.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA
A

Yeah. And then, in terms of production and production breakdown, so I think I talked about the bridge between, let's say, the Q2 discussion on production and the current outlook for 2023. And then, your specific question on Valhall, I agree with your numbers, but Valhall, at least in Q4, has actually been a pretty decent contributor and we're now seeing quite a few of the wells that had been falling over on Valhall being put back on stream in the current intervention campaign. So, if Valhall continued to perform the way they have done now the last few months, I think they certainly have a P50 of 65 and maybe a possibility of being a bit higher in 2023.

The key component on the Valhall production is not necessarily the facilities as such, but it's the chalk influx in these wells, which are pretty hard to predict from, let's say, quarter to quarter. So, that's the key differential on Valhall. It's the chalk influx in the singular wells.

Yoann Charenton
Analyst, Société Générale SA (UK)
Q

Thank you, both, for the color. Have a nice day.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

A

All right. Then, we have currently three questions in queue. So, number one is James Thompson from JPMorgan. Please go ahead, James.

James Thompson
Analyst, JPMorgan Securities Plc

Q

Good morning, everybody. Thanks for taking the questions. I'll try and keep it quick. Karl, could you maybe just give us a little bit more color on the Phase 2 ramp-up on Sverdrup? I mean I know it's a few days later than you thought, but it would be interesting to understand well performance, et cetera? I mean it looks like it's beaming up quite quickly. So it'd be good to just understand how that's gone versus your expectations.

Secondly, David, could you give us some views about I guess the company view on leverage from here? I mean, obviously, 0.2 times net debt-to-EBITDA is very, very strong. Clearly, going into a bit of a CapEx cycle, it would be good to understand where you are comfortable as we kind of work our way through this CapEx program from here.

And finally, just maybe, David, for you as well, a bit of a detailed question. But talk about the currency translation differences kind of acquired with Lundin, has that now gone away? Is that what we should take in your comments and we shouldn't expect that volatility into 2023? Thanks.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

So, let's start with Johan Sverdrup. I think it's fair to say that, in Aker BP, we had a bit of a more aggressive assessment of start-up date than the operator had communicated. The ramp-up has been going quite well, actually. There has been some minor hiccups as is I would say normal and when you start up facilities of this size, but the ramp-up is pretty much on plan, with the exception that it's, in our plans, a bit delayed compared to what we communicated back in Q2. I think, to give some more color there, I think the operator is actually doing quite a stellar job on the commissioning and start-up of Phase 2, as they actually did on Phase 1. So, I don't have any – I don't really have any worries about the ramp-up of Phase 2 as such. It's all coming along pretty nicely.

And then, let's move on to debt.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah, I can take that.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

Yeah, sure.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. Yeah. So, in terms of leverage ratio, as you mentioned, James, yes, we have de-levered the balance sheet quite significantly over a period when the oil prices have been very constructive. Our financial framework is linked to our investment-grade credit rating and then believe that that is key in order to ensure that we have financial capacity and also flexibility in the years ahead given the investment program that we have.

And we typically talk internally about a threshold of not exceeding a leverage ratio of 1.5 net debt-to-EBITDAX over a period of time. So, of course, we are quite significantly below that, but that doesn't mean that we plan to sort of lever up the balance sheet in the shorter term. But given the volatility of commodity prices, we think that it's good to build robustness when the prices are as constructive as they have been in the last year, year-and-a-half.

In terms of the foreign exchange question, with regards to the Lundin transaction, yes, as I said in my presentation, we have now either liquidated or consolidated into Aker BP the entities which had a NOK as functional currency. So, we don't expect any sort of other comprehensive income linked to the Lundin transaction in future quarters.

James Thompson Q
Analyst, JPMorgan Securities Plc

Okay. Brilliant. And maybe just one final modeling point, just in terms of OpEx, are you going to be able to hold that $7 to $8 range ahead of the start-up of Yggdrasil or should we expect it to kind of creep higher until that point? Thanks.

Karl Johnny Hersvik A
Chief Executive Officer, Aker BP ASA

That's a good question. I certainly hope that we'll be able to stay on this level. It would depend largely on – well, the variable cost will depend on electricity cost to a certain extent, but there are also discussions on transport tariffs and booking fees and other production-related costs. And then, of course, as these assets mature, we'll also see a certain increase in maintenance cost. But hopefully, that will be offset by our improvement program along the same lines as well. So, I certainly hope that we will end up in the same range. Modeling wise, we are actually predicting that we will be pretty flat in terms of OpEx per BOE internally.

James Thompson Q
Analyst, JPMorgan Securities Plc

Great. Thanks, guys. I'll hand it over.

Kjetil Bakken A
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

Yes. Then actually looks like the final question of today comes from James Hosie from Barclays. So, James, please go ahead.

James Hosie Q
Analyst, Barclays Capital Securities Ltd.

Yeah, thank you. I guess just to ask you about the capital allocation priorities through 2028. On slide 44, this indicates you've got like $10 billion allocated between debt reduction dividends at current oil prices. Should we just assume the vast majority of that goes to dividends or do we need to reduce it to allow for your possible ambitions with further acquisitions or other growth?

Karl Johnny Hersvik A
Chief Executive Officer, Aker BP ASA

Yeah, you can do that.

David Torvik Tønne
Chief Financial Officer, Aker BP ASA

A

Yeah. So it's a good question, right. I don't necessarily think that it's an easy answer to that because, of course, it depends on many aspects, including, of course, commodity price environment and so on, right. But I think, in general, we believe that the cash flow generation is very, very robust and that we have capacity to increase dividends in line with sort of the minimum of 5% per year. And then it might be that we choose to refinance the debt maturities that we have in 2025 and 2026 with new additional debt, and it might be that we actually choose to repay some of that, but that's still ongoing discussions.

And then I think that the last part of your question is linked to could part of our financial capacity be used for M&A. In the end, right, our M&A transactions is all about creating value. So we have a robust balance sheet with a lot of financial flexibility, and that's also one of the reasons why we're building that flexibility. So if the right opportunities arise, we, of course, we'll use that flexibility to create additional value. But the transactions in themself, of course, needs to be value-accretive and build further robustness and further capacity for cash flow generation.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

A

But as you probably know, James, there is no specific point in our capital allocation policy that talks about building up a war chest for future M&As. So I think that's a good sign of how we're thinking about M&As.

James Hosie
Analyst, Barclays Capital Securities Ltd.

Q

Okay. Thank you.

Kjetil Bakken
Vice President-Corporate Finance & Investor Relations, Aker BP ASA

I guess that's it.

Karl Johnny Hersvik
Chief Executive Officer, Aker BP ASA

That's it. Then I think I'll thank you all for participating in this Q4 for Aker BP for 2022. It's been a fantastic year for us and we're looking forward to 2023 and look forward to seeing you again in Q1 2023. Thank you so much and have a great day.