Upstream Seminar

London, 11 October 2012

Speakers:

Claudio Descalzi - COO Exploration & Production
Luca Bertelli - EVP Exploration & Unconventional
Roberto Casula - EVP Africa & Middle East
Massimo Mondazzi - EVP Central Asia, Far East & Pacific

Claudio Descalzi

Good afternoon ladies and gentlemen, and welcome to our 2012 Upstream Seminar.

This is our third dedicated upstream event. Last year we held it in Congo, highlighting how the Eni model of relations with host countries supports resource access and long term production growth.

Today, as well as giving you an update on our growth projects, we aim to provide additional insight into the way we do things, our distinctive competences and processes, and how that positions us well to meet industry challenges.

The e&p industry faces four main challenges.
1. The first is finding resources. Over the last 10 years, the industry has been increasingly less confident about finding material opportunities beyond unconventionals.
2. The second is turning resources into reserves and production. The oil and gas industry's track record on execution is disappointing, with average delays of around 20% and cost overruns above 25%.
3. Thirdly, the industry has to work very hard to manage exisiting production, fighting field depletion, which on average runs at around 10% per year
4. And the fourth challenge is to preserve the value of resources, protecting them from possible operational and political disruptions.

How are we responding to these challenges?

- In terms of finding resources, we have delivered outstanding results. The strategic approach which underpins target selection has transformed our long-term growth profile and will support our competitive position in exploration going forwards.
- On development, we have a strong project pipeline. We are not immune to industry trends, which have caused some limited delays, but we are improving our delivery capacity going foward.
- Reducing decline rates and enhancing recovery factors has historically been an area of strength for Eni, thanks to our focus on giant conventional projects and our leading performance in reservoir management and maintenance.
- Lastly, our approach to risk management. Our record on operational accidents is very robust. And we have built excellent relationships with host countries: our Eni model provides not just capital and technology, but also consistent, long-term commitment and domestic engagement.

Let me now take you through each of these stages in turn – starting with exploration

In exploration, we can count on distinctive competences, which we are deploying through new and improved processes.

1. First, we have strengthened the way that we define our long-term exploration objectives, consolidating the central strategic studies group. This is the group that runs regional geological studies to identify new emerging plays, and which, for example, secured access to the Rovuma Basin in Mozambique, the Block 15/06 in Angola and our prospects in Ghana.
2. Second, we have changed the way in which we select exploration prospects, focusing on a smaller number of high risk – high reward opportunities. To do this more effectively, we centralised the prospect selection process. Potential plays identified by the different business units are evaluated via a peer review, carried out by senior exploration managers and knowledge owners. Prospects are scored in terms of potential, timing and costs of development, with direct contribution from top-level managers in development, operations and R&D.
3. Thirdly, we have increased our focus on the time to market of our portfolio, setting up a specific function to accelerate the appraisal campaign of potentially significant discoveries, and maintaining focus on near-field exploration with fast startup. As a result of this effort, about 40% of the discoveries we made from 2009 to 2011 will reach production in less than 4 years, and a further 55% between 5 and 8 years.
4. Finally, we have developed our own key technologies on imaging and geological modelling, and indeed run the whole of the exploration process in-house.

This strengthened approach has delivered outstanding results.

Over the past four years, eni has discovered one billion barrels of resources per year on average - with a cumulative total of more than 6 billion barrels including the first half of 2012.

This largely exceeds our aggregated production over the same period of time, which is 2.8 billion barrels.

Moreover, our exploration successes are not limited to our historical legacy areas. We have opened entirely new plays and created new, large core areas, such as the discoveries in the Norwegian Barents Sea and East Africa.

Looking forwards, 3 key factors will continue to underpin our exploration strategy.

First, we will continue to seek high-materiality plays, which account for 55% of risked exploration resources. Notably, we will consolidate our presence in the Norwegian and Russian Barents Sea and increase our position in East Africa.

Second: we will enhance our position in emerging basins – for example West Africa pre-salt and transform margins – which account for 35% of our risked exploration resources.

And third, we will aim for rapid time to market and cost effectiveness. We will continue to focus on near field exploration, for example in North Africa, and on material prospects with synergies to existing infrastructures, such as the Pacific Basin.

We are already derisking our future exploration through seismic and the wells we are drilling. We are fully on the way to meeting our plan target of 4 bn boe of new resources between 2012 and 2015.

I will now hand you over to Luca for a description of our best potential areas.

Luca Bertelli

Thank you Claudio.

Good afternoon ladies and gentlemen.

I will take you through our exploration plays in some emerging areas where we have a leading position - such as the Barents Sea and East Africa - as well as in regions where we are building up materiality such as West Africa pre-salt, Pacific basin gas and unconventional.

The exploration of the Norwegian Barents Sea is a successful and qualifying story for us since we started in 1982.

After years of studies and analyzing the results of the previous exploration we adopted a new conceptual model, looking for oil not in basin depo centers but in the shallow traps, on the flanks of the main basins. This is how we discovered the first commercial oil accumulation in the Barents, Goliat. This model properly adapted is now also delivering very promising results in the exploration of the Biornoya Basin where, with Statoil, we discovered Skrugard and Havis.

We have just completed Salina, a G&C discovery which will be followed by a further appraisal phase. We have a very exciting program for 2013 with 5 further wells. One of these, Bonna, is a high-materiality gas prospect in underexplored area of the Barents Sea. The remaining 4 are oil & gas prospects in the Skrugard-Havis trend. We have already secured two-drilling-rigs for the entire drilling campaign.

Based on this experience, we are well prepared for the 22nd licensing round on the Norwegian Continental Shelf.

We are also excited about our new sizeable prospects in the Russian Barents Sea, that we will explore in cooperation with Rosneft. The blocks have a combined acreage of 55.000 sq km and we expect oil & gas giant potential both in Mesozoic and Paleozoic sequences. A joint eni-Rosneft team is already at work finalizing seismic contracts and the related enviromental impact studies.

Let's now turn to East Africa, another emerging world class hydrocarbon province in which Eni has established a leading position with early mover advantage.

To explore the Rovuma Deep Water we developed innovative geological models for turbiditic and contouritic deposits, also using information taken from West African successes on stratigraphic trap exploration , and from the database of our past exploration experience in Tanzania where eni discovered Gas in the 70s and 80s.

Following the results of these models in Mozambique, we are extrapolating their use to other East African basins.

We have already acquired 3 large blocks in the deep and ultra deep water of the Lamu Basin in Kenya, and we are screening new East Africa deep water opportunities to further consolidate our position.

And now I will talk about the largest ever discovery in eni's exploration history, the Mamba Complex in the Rovuma Basin, Offshore Mozambique .

The Rovuma Basin has tertiary age depositional systems which are unprecedented for size and characteristics.

The reservoirs are turbidites but not of a standard type. Due to a strong interaction of the sea bottom currents, which removed the fines during the debris flow, we do not have the classical fining upward sequences but massive blocky sands of exceptional thickness, up to 500 m.

Petrophysical properties are excellent, with good porosity and outstanding permeability. We have pressure communication and hydraulic continuity in wells that are 25 to 30 km away from each other.

As a result of the geology, wells are extremely productive, with a large drainage area - a fact confirmed by three production tests performed in different reservoirs of the Mamba Complex.

This means that this huge resource base can be exploited with a limited number of producing wells that will make the upstream project highly efficient.

Despite water depths of up to 2000 m and reservoir depths of between 4000-5500 m, wells require just a few weeks to drill, since all the reservoirs are in hydrostatic pressure.

To summarize: the Rovuma Basin is confirming its world class standing with over one hundred Tcf of discovered resources and unique qualities of the reservoir.

Another emerging play in which eni is consolidating its position is West Africa pre-salt.

Eni has the largest acreage position in the pre-salt play onshore and in shallow water, spanning from Gabon to Angola and we operate in Congo the Giant pre-salt Mboundi field with almost 2.0 Billions of Oil in place.

This kind of exploration has material potential, with fast development time at very low cost.

We also have very promising deepwater pre-salt acreage in Angola. Here our model mirrors the model proven by the discoveries in the Santos and Campos basin in Brazil.

In terms of hydrocarbons, we expect to find similarities with those discovered in the Santos and Campos basins, light volatile oil with high GOR, but reservoirs can be slightly different as in Angola we may expect carbonates , microbialites but also clastics.

We expect multiple discoveries with viable commercial potential. We consider the Cameia discovery done by Cobalt in Block 21 as an encouraging sign of an active petroleum system.

Our exploration investment on these plays may reach 600 M$, with up to 19 wells over the next four years

The Pacific Basin is one of our main growth targets. We have assembled a sizeable portfolio and are now well positioned to add further opportunities.

Our strategic studies group has been running extensive regional studies in the area, to identify material, fast time-to-market opportunities. We have been particularly interested in material gas plays that could be linked to existing LNG infrastructure with available capacity.

This led to the selection of a number of blocks.

In Indonesia, Arguni I Block will target Jurassic and Paleozoic gas potential, while the blocks in Offshore Kalimantan will target multi tcf gas in Pliocene and Miocene sequences. We plan to acquire 3D seismic in Arguni during 2013 and to drill in early 2014, while we will drill offshore Kalimantan in late 2014.

In Australia, Evans Shoal, Heron and Blackwood are located within reach of existing LNG infrastructures. We are currently drilling our first exploration well, Heron South, which will be followed by an Evans Shoal well at the beginning of 2014

.

Moreover, we increased our gas prosepctivity by entering Vietnam with three offshore licenses, and acquiring rights to one Block in the deep water of China. We plan to drill 2 exploration wells in 2013 in Vietnam, while we will drill in China DW in 2014.

We will continue to seek new Opportunities in the Indo-Pacific basins to enlarge our exploration portfolio base.

Lastly, unconventionals. Eni is a very conventional company, and we have chosen not to add unoconventional exposure through acquisitions but through a targeted approach.

We look for robust geological plays in areas where there are synergies with existing operations, where unit costs are low, in countries with an already developed gas transport infrastructure and where the gas market is favourable.

We are progressing in all of the areas where we have identified opportunities, and in particular in Eastern Europe.

In Poland, we have completed the drilling and the coring of three wells. Cores have been extensively analyzed in our labs to understand the mineralogical composition and textural setting of the shales. We have drilled our first horizontal drain and started fracking.

In Ukraine we have acquired thies year rights to further acreage, and we plan to drill our first well by end of 2013 or beginning of 2014.

Outside Europe, we have ongoing negotiations for gas shale blocks with Sonatrach in Algeria, and with the Pakistani Government.

Our negotiations with potential chinese partners are progressing, and may lead to exploration acreage for gas shales in the Sichuan and Guanxi basins.

Today our total unconventional acreage is about 6000 Sqkm

Thank you for your attention, I will now hand you back to Claudio

Claudio Descalzi

Thank you Luca.

Leveraging on our exploration successes and our significant portfolio of resources, eni's objective continues to be to grow organically.

We now have to be effective and efficient in bringing resources to production, overcoming the execution challenges which affect our industry.

There are two main reasons why some E&P projects are delayed: weak performance on execution, and capacity constraints in the market.

1. Disappointing performance on execution has a number of common causes across the industry, such as:

- Lack of flexibility and cost efficiency of EPC-turn key contracts
- Lack of quality of front-end activities, implying extensive engineering re-work and project changes after sanction
- Difficulties during commissioning

These problems are rooted in the evolution of the industry, where outsourcing to EPC contractors of project management and front-end engineering led, over the years, to a loss of competences and grip.

2. Regarding capacity constraints, we are starting to see the impact of a prolonged period of high oil prices on oil services, in terms of:

- Construction capacity saturation of major ship yards
- Longer delivery times of critical equipment.

As a result of these challenges, the industry is currently running at an average delay of 20% on project timing.

We are well positioned with regards to these industry challenges; our project portfolio carries low execution risk, and our access to competences remains strong, as we have historically outsourced less than our industry.

However, project execution and capacity constraints are affecting some operated and non operated projects in our portfolio. As previously mentioned, MLE and El Merk in Algeria, Jasmine in UK, and Angola LNG have encountered various project execution issues, while Goliat in Norway and Block 15/06 in Angola have been impacted by capacity constraints. We will elaborate on individual projects during the rest of the presentation.

We are not happy with the peformance of these projects, and have taken immediate steps to mitigate the impacts. However, it is worth remembering that:

- The delays we are experiencing only affect a limited portion of our strong and diversified pipeline of 120 new projects, and tend to be a matter of months. Indeed, many of the delayed projects, such as MLE and Angola LNG, are expected to start up shortly.

- While these delays will impact the timing profile of our production growth especially in the short term, we confirm our target growth rate of more than 3% a year to 2015 and 3% a year beyond, also thanks to the contingencies embedded in our plan.

- Meanwhile, our profitability remains robust; we confirm an average IRR on new projects greater than 20%

That said, and in light of our significant future developments, we are putting in place a number of initiatives to strengthen our capacity to deliver projects on time and on budget.

1. First, enhancing our engineering and project management capabilities.
Building on our existing base of around 2000 engineering resources, we are in-sourcing key competences and increasing the number of dedicated people.

2. Second, strengthening our construction and commissioning organization, to increase grip on site activities.

These two initiatives will require 1200 new hires, as well as the redeployment of some people from other projects, leveraging on the pool of skills and experience which will become available after the Kashagan handover.

To tackle the second industry challenge, capacity constraints, we are progressing on our modularization efforts. We are putting in place long-term frame agreements for major supplies, using standardized specifications to speed up the pre-award process. These include subsea equipment, christmas trees, power generation modules and compressors. In parallel we are increasing focus on supply chain programming to optimize our order flow.

As a result of these efforts, we will increase direct control and governance, reducing uncertainties in cost and timing for new large projects in our hubs in Mozambique, Barents Sea, Pacific Basin, West Africa and Venezuela.

After this overview of how we are strengthening our development capabilities, we will now give you an update on our main projects.

Roberto will start off with Africa.

Roberto Casula

Thank you Claudio.

I am pleased to have the opportunity to talk about our African business.

Historically, Africa has been the backbone of Eni's production and growth, and it will be a key driver of our future.

Our asset base is robust;, we operate 1.5mboe/d, of which around 1m equity.

We have major development projects with 5 Bboe of 2P reserves, with significant exploration upside of 4.7 Bboe of risked resources.

Our history and healthy long-term relationships within the continent position us well to gain further access to fresh opportunities.

Allow me to take you through 2 of eni's African hubs.

We shall start with North Africa and in particular with Libya.

Eni is focused on 2 main objectives: the restoration of production, after the revolution in 2011, and new development projects.

All producing fields are back on line. Our equity production is 240 kboed which is around 70% of capacity.

We are currently working on
1) The giant offshore Bahr Essalam Field where 3 wells out of 26 are yet to be restored
2) The giant onshore Wafa field, where plan is to tie-in 8 new wells.
3) As for the Abu Attifel and Elephant oil fields, more maintenance on water injection is required to return production to pre-crisis levels.

Previous indications were that full production could be possibly restored by the end of 2012. Owing to the important transition through which the country is currently undergoing, this assumption may now be somewhat optimistic.
Nevertheless, we continue to work well, with the National Oil Corporation, to complete the full production recovery, and we maintain our positive outlook for the country and its potential.

In terms of new developments, a basket of 900 Mboe reserves is there to be taken to production through projects with investments amounting to $9bn such as Bahr Essalam Phase 2 , structures A , E, T&U. eni is working jointly with NOC to define the next steps for both investment and production growth.

As far as Egypt is concerned, production is performing well; we are currently over budget by about 5%.

The main focus lies in maintaining production from legacy fields through optimization and nearby field exploration.

A good example is the recent success at Emry Deep, where we have now tied-in two wells and are producing approx. 12 kboed of oil. This discovery had a time to market of 4 months at a cost of less than 6 M$.

As far as gas is concerned, we are the leading IOC, satisfying 30% of domestic demand through our operated production. We have already made some large discoveries, which may turn into additional developments once appropriate commercial terms are in place.

While Libya and Egypt are the pillars of the North African production, Algeria is acquiring ever growing importance.

Today Eni produces about 75 kboed, mainly oil, and expects this production to reach 115 kboed in 2014 thanks to the new gas production derived from MLE and CAFC.

As Claudio mentioned, these projects have experienced delays during the construction phase – they are governed by an EPC contract which, by its nature, does not allow sufficient flexibility to adapt to changing technical and market requirements.

Regardless, in MLE we completed 550 km of export pipelines and delivered 24 wells. The Central Processing Facilities are around 99% complete and commissioning activities are ongoing.

Start-up of the gas production is expected by the end of this year.

I will now turn our attention to West Africa…

…starting with Angola and block 15/06, our major giant development in this country.

The West Hub will start-up in the second half of 2014 as a result of a delay caused by market constraints over key equipment.

The first drilling campaign with Saipem's Scarabeo 7 is ongoing for the first 4 wells. The second drilling campaign will commence in the second half of 2013. There will be a total of 16 wells, 10 of which are producers and 6 injectors.

Meanwhile, the FPSO is undergoing refurbishment works in Singapore and is expected to arrive on site in February 2014.

As to the the East Hub, we expect to take FID in 2013. While this project benefits from design and logistic synergies with the West Hub, it also has a number of specific characteristics related to the presence of two different types of oil in the discovered structures of Cabaça and its satellites.

Block 15/06 has further potential from the definition of exploration upside and the development of the Lira gas discovery.

We estimate peak production from the West hub of 90kbbl\d (equity 27kbbl\d) and 170 kbbl\d (equity 51k bbl\d) from the whole block including the East Hub.

As for Nigeria, OPL 245 is the most recent addition to our portfolio of giants in Sub-Saharan Africa, with almost 500 Million barrels of reserves and additional exploration upside.

The drilling campaign is set to commence in the next few weeks. We are planning for a first production phase on the Etan discovery with start-up in late 2015 / early 2016. The development will encompass a dedicated FPSO and 8 wells, of which 4 are producers - and 4 injectors. Peak production will reach 40 kboed of oil.

Full field development of both Etan and Zabazaba discoveries will follow with an overall peak production of approx. 180 kboed.

Lastly, an update on the M'Boundi integrated project in Congo. I can see many people here who visited the field with us last year.

M'Boundi water and gas injection projects are on track with total capex of 930 M$.

The water system is currently functioning and being upgraded to a capacity of 200 kbwd. The gas project - which includes 2 trains for gas compression - is due to be completed by early 2013.

These two initiatives will allow eni not only to sustain and increase the oil production but also to reach its objective of zero onshore gas flaring in Congo in the coming months, once again being in the forefront in reduction of the environmental impact of oil & gas activities in Africa.

And now moving on to East Africa...

The jewel in eni's east african crown is Mozambique.

We originally had very high expectations for Mozambique: they have been confirmed and even surpassed. As Luca mentioned, the reservoir has proven to be of outstanding extension, thickness and quality. Let me show you as an example a picture taken during our production test (foto).

Since the very beginning we have worked to minimise the time to market of this project, for example performing engineering studies alongside exploration.

In terms of development, with the gas that is in straddling levels, we are continuing discussions with Area 1 regarding unitization, the joint plan of development and the onshore LNG plant that this gas will feed.

At the same time, on resources entirely in Area 4 - at least 20 tcf - we are evaluating a number of separate development options.

In terms of development cost, Mozambique is well placed amongst its peers in the Far East, with a highly competitive break-even price compared to worldwide LNG production forecasts.

Alongside LNG, we are also examining other monetization options.

In line with our model of cooperation and domestic engagement, we plan to use some of the gas for domestic power generation, building a power plant jointly with the government of Mozambique.

Regional export options are also being considered; we are currently studying the potential application of CNG technologies to serve neighboring countries.

Our overall aim is to contribute to Mozambique's objective of becoming the new model of global integrated gas hub, something which we have the experience and capabilities to deliver.

To sum up, Africa has long been the mainstay of our growth and, thanks to the projects and opportunities outlined today, it will continue to drive Eni's growth for the next decade.

Our performance to date highlights our strong competitive position on the continent: over the past 10 years we have delivered a growth rate which far outstrips the performance of other majors.

Our projects will ensure growth of around 3% a year on average to 2022, with potential further upside from exploration, for which Africa is a key area.

Thank you for your attention, I will now hand you over to Massimo Mondazzi.

Massimo Mondazzi

Thank you Roberto. Ladies and gentlemen good afternoon. Today I will take you through our prospects in two key hubs in our worldwide portfolio:

- Kazakhstan, one of our legacy countries where we have interests in two supergiant fields, and
- the growing Far East and Pacific Region

Kazakhstan currently accounts for more then 100 thousand barrels per day of equity production thanks to the Karachaganak field , more than 2bn barrels of 3P reserves to be produced from Kashagan and Karachaganak and a level of production in 2020 that will be around 180-200 thousand barrels.
Today I will focus on this expected industrial growth, as the recent agreements with the Repubblic of Kazakhstan have already paved the way for future developments.

Meanwhile, the Far East is an example of our distinctive approach to building up a material position quickly through targeted exploration farm-ins, the rapid assessment of potential and efficient developments.
As a result of this approach, since the upstream seminar in 2010 we have increased our risked potential portfolio by 50%.

First, an update on Karachaganak.
Following the settlement agreement between the operator and the Republic of Kazakhstan, which sanctioned the entry of the state oil & gas company with a 10% stake and the end of all claims asserted by the parties, everyone is focused entirely on future field developments.

There is certainly a lot of potential: the reserves still to be produced are estimated at about 5 billion barrels, approximately four times the reserves already produced, and production costs are well below eni average.

The study of the new development is now underway, but what we expect for the future is not a single, monolithic phase comprising huge investments upfront and additional production later on.

Rather, the new development will comprise a series of sequential stages, each with a defined scope, which will allow an immediate extension of the liquids production plateau. Then, we expect further substantial growth in gas production starting in 2019-2020.

Let's move on to Kashagan. The overall progress towards the so-called Kashagan Commercial Production is currently 99.8%. We are at the last phase of mechanical completion while commissioning and pre-start up activities are at an advanced stage.

By December Tranche1 onshore (which represents roughly 70% of the overall onshore facilities) and A island (which will entirely supply the first production), are planned to be handed over to the Production organization and tested with sweet hydrocarbons. And this achievement will represent de facto the start up of these facilities. Immediately afterwards, the remaining onshore and offshore facilities, including the main hub, Island D, are expected to be handed over.

Our priorities remain:

- to guarantee a safe completion, with assurance processes set beyond the oil industry practices, and
- to release a fully efficient plant to ensure high stability and continuity in future operations.

While meeting these priorities, we expect to start up before June 2013, the date agreed with the Republic of Kazakhstan. The opening of the wells is expected by the end of IQ - beginning of II Q 2013.

Eni share of development costs incurred so far equals 6.9 B$. The final overall costs will be in the range of 13 $ per barrel to be produced. A number that compares very well not only with projects with similar environmental and technological challenges, but also with conventional projects.

Let come back now to the Far East. I already mentioned that, since the upstream seminar in 2010, we have increased our risked potential portfolio by 50% to 1,5 Bl barrels.

Luca indicated that our exploration in this area is mainly seeking gas in proved basins and from licenses operated by us in which we retain high interest. But let me further qualify from a commercial point of view the choices we have made in terms of portfolio.

All these assets are in the proximity of infrastructures with existing or expandable capacity that will give us access to a very high price/high demand gas market.

In Indonesia, East Sepinggan is located in the hydrocarbon-rich Kutai Basin, about 170 km from the Bontang liquefaction facility from which we exported gas in 2011 at an average price close to 20 $/Mmbtu. Arguni I, in West Papua, is a few kilometers from the Tangguh liquefaction plant.

In Australia in 2011 we acquired a 50% interest and operatorship of Heron and Blackwood offshore fields as well as a 32.5% interest in the Evans Shoal field. These fields are close to each other, allowing for potential synergies for development that could be either through a FLNG or through the expansion of existing onshore facilities. Bayu Undan plant is approximately 300 km away.

Finally Vietnam. Even though the facilities are still to be built, we see high prospectivity and strong gas demand both in country and just outside. Overall eni risked resources are about 200 million barrels.

The overall exploration potential in the Far East will be assessed very soon. The work program for the next two years foresees 19 wells to appraise approximately 60% of the total resources, of which 17% in the next six months and 29% by next year. The cost of this activity for eni is estimated at US $ 700 million and corresponds to a projected unit exploration cost below 1 $/barrel.

Our goal is not only to speed up the appraisal of the existing potential but also to quickly bring the discovered reserves on stream.

And here are three examples of fast track development projects, namely Kitan in Australia, Pakistan and Jangkrik in Indonesia.

First of all the deep offshore Kitan project, in Australia, which came on stream only three and a half years after commercial discovery, while at the same time keeping project costs within budget and maintaining very high HSE standards.

The development concept is based on a stand alone dedicated FPSO which processes oil flowing from three vertical wells with subsea completions.

Furthermore, we are recording significant overperformance of the field, that led to increase our estimate of 2P reserves by 60% versus our 2010 estimates, making the project track record even more positive.

Second I would like to highlight our track record in, Pakistan, a country in which eni is the first international oil company in terms of production and reserves.

Production of 55 thousand barrels per day will be steadily maintained, if not increased, by carrying out two main activities streams:

1. field exploration in mature basins close to the existing production infrastructure which allows production start up within about six months from the discovery. The recent operated discovery of Badhra North 1 , expected on stream in just two month, is an example of our capability. eni's overall conventional exploration potential in the country is approximately 280 million barrels;

2. Tight gas-related activity, after the recent Kadanwari pilot well that recorded excellent results and will be tied in to production facilities in about two months' time.

Third, the Jangkrik complex in Indonesia. This project, for which the FID is expected next year, envisages production exported to the Bontang facility through 11 subsea wells connected with an FPU.

First Gas is expected in only 5 years from the commercial discovery of Jangkrik Main and 4 years from that of Jangkrik North East.

The peak flow rate of the two fields will be over 80 thousand barrels per day (41 kboe eni equity).

Finally here is our production forecast for the Far East.

The existing assets in Australia and Indonesia, together with the newly discovered reserves, are expected to take the production up to 140 thousand barrels per day by 2020, more than doubling the current performance, corresponding to a 10% CAGR compared to 2010.

The major contributions to this growth will come from the new Indonesian projects of Jangkrik complex, Jau and the non-operated IDD, as well as from already producing fields in Australia.

On top of this, by 2020 we expect an additional 120 thousand barrels per day from the mature exploration activity and new ventures, bringing the overall CAGR to 17%.

Among the most significant contributions from this segment it is worth mentioning the Heron, Blackwood and Evans Shoal licenses in Australia and the East Sepinggan and Arguni licenses in Indonesia.

Thank you very much for your attention, and now I will hand you back to Claudio.

Claudio Descalzi

Thank you Massimo. And now, I will give you some updates on other hubs.

I will start with the Barents Sea, and in particular with Goliat.

The project is progressing well. We have installed the 8 drilling templates, and drilling will start on monday, as per plan. Meanwhile, major deliveries of subsea equipment have already been completed, and the installation campaign is progressing. Construction of the facilities to supply power from shore is also on track.

The FPSO is a new concept, with a round hull designed to withstand meteocean conditions, and fully winterized topisdes. Power is generated onshore to reduce CO2 emissions.

Capacity constraints in the Hyundai yard in South Korea have caused a delay in the construction of the FPSO, which has resulted in a slippage of the overall start up date from YE 2013 to 3Q 2014.

We increased company supervision at the yard, complementing the Hyundai teams: we now have about 200 supervisors working, and we set up regular meetings with top management to follow up construction directly.

Moving on to the Yamal peninsula, Samburgskoye started production in April, ahead of schedule, with 16 wells feeding the 1st gas and condensate train. Remaining trains are expected to be onstream by 1Q 2013: the drilling of 10 further wells and plant expansion activities are ongoing.

Work is also ongoing on the oil development: we are drilling the first wells, and the oil plant site is in execution. We are on track to start up by 1H 2013.

Overall, the development plan encompasses more than 150 wells, gas and condensate separation, oil treatment and water injection facilities.

In parallel, the company is now working to achieve startup of Urengoyskoye and Yaro-Yakhinskoye in 2014.

Finally, in Venezuela we are proceeding with Perla and Junin 5.

After some months of discussions, Perla has recently obtained PoD approval and we are now ready to advance to the execution phase.
We are in the process of awarding the contracts for platform fabrication and installation, and by year-end the initial works for the onshore processing facilities will start. First gas is expected by 1H 2014.

On Junin 5, we are executing Phase 1 which includes the drilling of 176 wells and the use of PDVSA facilities to reach a production target of 75 kboed.

Drilling activities are gradually stepping up: the first rig has already drilled two wells, achieving better than expected results. A second rig is about to start operating and we will have the next two rigs online in the next few months.

FID for phase two has not yet been taken; evaluation activities will take until end 2014.

Let's now turn to our operational performance. Managing producing fields and optimizing them for the long term is eni's strength.

This is the foundation on which we build our future growth.
This strength comes from our strategic decision to focus on giant, conventional assets, such as our legacy fields in Africa where we fought depletion successfully over the last decades.

And on top of that, we have deployed specific competences and processes to operate facilities and optimize the reservoirs for the long term.

To manage our assets, we have two strong central functions, Production & Maintenance and Reservoir Management, that interact, validate and challenge programs and proposals from operating units.

These functions run specific performance enhancement programs. For example:

- Production checks are programs focused on improving main fields' overall asset integrity over the medium to long term. The program covers each main asset once every 3 years, through a field review of about three months, to identify reservoir management plans and interventions on both subsurface and surface facilities.
- On the other hand, Well-Bore Reviews are core reservoir management activities, focused on short-term well performance to identify possible upside and define relevant well interventions. In 2011, 10 major studies achieved an incremental production of about 20 kboed.

In terms of reservoir management, we have been finetuning our approach continuously over the years, reaching recovery factors which are well beyond initial expectations.

For example, our North African mature fields have RF higher than 50%, with peaks of 55% in El Borma in Tunisia and Bu Attifel in Libya.

In terms of operational efficiency, our results are outstanding.

Average downtime in our operated fields is 3.5%, compared to 9% on the non-operated fields in our portfolio.

This is the result of a distinctive approach to maintenance, which has never been outsourced.

As a final point, I will provide elements on our strategy to manage risk.

Our key focus is the mitigation of operational risk - in particular the risk of blowouts and spills. Operational risk is the biggest potential threat to upstream activities, in environmental, financial and reputational terms.

Risk mitigation starts from the quality of our selected assets and having direct control on operations.

- We have been focusing on assets with low execution risks, either onshore or in shallow water. Our exposure to HP/HT wells, which have the highest operational risks, is extremely low and represents only 3% of the total wells to be drilled in the next four years.

- In terms of direct control on operations, we operate 3 mboe/d of gross production and plan to increase this to approx 4.5 mboe/d by 2015. This will allow us to deploy our competencies and know-how.

One of the ways in which we ensure long-term, stable presence in the countries we operate in is through our "eni model", our distinctive approach to cooperation with host communities, that some of you saw in action last year in Congo.

Through this approach we commit to invest in long-term initiatives that benefit the country. This way, we become local players, and we protect the value of our presence in the country. Ultimately, in each country in which we operate, we are a local company with skills and standards of an international major.

Our model has 6 different legs, but today I will focus on two of them.

First, local content. In the last 10 years we have increased the overall number of locals employed in our organization by 55% to 4,200 and developed the growth of local managers by 270% to 1000. In addition, eni favors local businesses and the direct acquisition of local goods and services.

Second, a specific example of access to energy is power generation. This leverages on our competences along the whole of the oil and gas value chain to convert gas flaring from an environmental risk to a development opportunity. Eni was the first IOC to invest in large combined-cycle power generation in Africa using flared gas. Today, our power stations in Nigeria and Congo account for 20% and 60% of domestic electricity production respectively.

In conclusion:

All of the projects and initiatives we have talked you through today add up to a confirmed growth target of more than 3% per year to 2015, and 3% per year to 2022.

Outstanding exploration results and our focus on organic growth have significantly reduced our finding and development costs over the last 5 years.

This has increased the value of our growth.

We expect this positive trend to continue, supported by:

1. Projects with materiality and fast time to market
2. Improved efficiency in the sanctioning process, and
3. increased direct control of the execution of our projects.

As a result, in the next four years our F&D costs will decline further, to an average of 14.5 dollars per barrel, despite increasing complexity of new projects and cost escalation in the industry.

As well as improving F&D costs, we confirm best-in-class efficiency in operations.

Our portfolio of giant and conventional assets, particularly in Africa, keeps our cost position among the leaders in the industry, with an average opex of around 7$/barrel in 2011.

Also in the future, through increased operatorship and continuing operational improvement, we will be able to maintain opex among the lowest in the industry.

We are about to reap the benefits of a long phase of investment.

The start-up of some large development projects in the near future - for instance Kashagan - will reduce inactive capital from the current 30% to less than 20%, driving higher returns on invested capital.

Lastly, new barrels will provide higher unit cashflows.

Under a flat oil price scenario, our cash flows per barrel in 2015 will increase more than 10% versus 2010. At 90 $/barrel, the improvement will exceed 15% and more than 30% with 115 $/barrel.

In conclusion, Eni is well placed to tackle the challenges we are seeing in our industry.

We have distinctive competitive advantages which come from our history, our culture and the competences of our people.

These add up to an exceptional track record in exploration, an industry-leading performance in fighting depletion and a unique approach to relationships with host countries.

We are in a stronger position than ever before to deliver sustainable long-term growth, bringing each of the 120 projects in our pipeline into production with the strong committment and dedication of all of us.

Thank you very much for your attention.

Together with my team - Antonio Vella, who takes care of operations, Enrico Cingolani, who runs Development, Guido Michelotti, EVP of R&D and Franco Magnani - our head of planning and control - and of course Sandro Bernini, our CFO, who is also here with us today, we will now be delighted to answer your questions.