UPSTREAM SEMINAR
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Claudio Descalzi

Good afternoon ladies and gentlemen
thank you very much for being with us today for eni's upstream seminar.
I am going to start by setting out Eni's upstream priorities within the context of the industry environment, explaining how we will build on our solid resource base to deliver profitable growth.

After that, I will hand you over to some key members of my team, who will take you through some of our most significant projects.

I will then wrap things up with some closing remarks, after which we will be pleased to answer your questions.

In the last few years, one of the key priorities for the industry has been to secure access to new resources in an increasingly challenging context.

However, in the short and medium term, the real issue is not that of finding new resources, that almost all the majors had showed to be able to find, but rather the efficiency with which existing resources are converted into reserves, the time to market of production and the effective management of field decline.
Indeed, when it comes to resources, we, in eni, are sitting on a total of 30 billion boe; a base we've built in recent years mostly through successful exploration, access to giants and selective acquisitions.
As we showed at the strategy presentation, these barrels are in legacy areas, where we are a leading operator, and largely related to conventional and low cost plays
Our priority in the short to medium term is to focus on the fast track development of this large potential while unlocking further upside through a balanced risk exploration strategy.
To develop and exploit our resource base more effectively and efficiently, we have adopted a new integrated organizational model and process.
Our new model puts production and time to market at the center, as a driver for both exploration strategy and the subsequent development.
Starting from exploration the focus must be that of looking for assets that we can bring to production in a reasonable time and cost effectively.
This new model will ensure that all organisational units share the same objective. Execution and follow up become the priority of each component of the team.
Eni can rely on a well balanced portfolio.
Out of 30 billion boe of resources, around 13 are 2P reserves.
Geographically, we are exposed to the most prolific African basins, as well as the FSU. Africa in particular is a core area for us. In many of the areas in which we operate our presence dates back 50 years, and we are the number 1 E&P company in the continent.
A large share of our resources is in onshore and conventional projects, and about 50% of our 2P reserves are in giant fields.
In addition, our portfolio is very well positioned to capture the upside in oil prices: about 60% of our gas is sold on the basis of long-term contracts with oil-linked formulas, which protects the value of our gas from the currently depressed spot market.

Our strong presence in Africa, our focus on conventional plays and our exposure to giant fields provide us with a strong operational basis, with positive impacts on the cost and value of our production.
Let’s take a closer look at the cost profile of our production.
In 2009 our average opex per barrel was 5.8$, benefiting in large part from our operations in Italy, Africa and the FSU.
For example, our North African fields in Egypt, Libya and Algeria have opex per boe of 3-4 $.
Meanwhile, the large portion of conventional plays in our portfolio is crucial to keeping our costs low. Maintenance and work-overs on these assets are less costly, more effective and easier to perform.
Also environmental costs and liabilities of conventional fields are lower.
Last but not least, our focus on giant projects provides benefits in terms of economies of scale.
Due to the start-up of new offshore projects, our average opex per barrel is expected to increase to 6.8$ by 2013 but is still among the most competitive in the industry, as we have limited exposure to higher cost environments and ultra deepwater.
The low-cost profile of our portfolio and of our reserves also contributes to maximise the return on our capex.
We plan to spend 32 billion euro in development over the next 4 years, in a context of increasing cost pressure.
About 25% is devoted to field production optimization projects through reservoir management activities, work-overs and infilling wells, which provide an additional production of 150-200 kboed each year. These projects have a payback period of less than 2 years and a return in excess of 40% at our price deck.
The average return on our growth oriented investments is around 20%, well in excess of our cost of capital.
Overall, we have one of the most attractive breakeven prices in the industry, which protects us from market downturns and leaves us exposed to material upsides at current prices.
This capex plan will support a CAGR of more than 2.5% over the next 4 years, with a scenario of 65$/boe flat.
We will achieve our 2.5% CAGR target in the medium term for 3 reasons:

- Firstly, the quality of our assets and our operational focus, which allow us to maintain the decline rate at about 3%;
- Secondly, the new production coming from our pipeline of start ups, of which 90% will be sanctioned within this year.
- And finally the solid contingency we applied, 150 kboed, which is twice our usual standards. This contingency takes into account potential risks, like delays in project rump-up or exogenous events and conditions.

Our growth profile remains robust even under higher price scenarios, while keeping the same level of contingency. At 90-100 $ we will reach a CAGR of 1.5%.
In the short term, while we are experiencing better than expected production performance in some countries, we are facing lower gas off-takes in Libya, as a result of the increased supply options in the Italian market and the lower spot prices.
The impact is currently about 60 k boed and we foresee a partial recovery in the last quarter of 2010, thus confirming our full year production target in line with 2009.
One of the key pillars of our growth in the next four years is our depletion rate, which at 3% is one of the lowest in the industry.

On this front, we benefit from our exposure to giant conventional plays in young basins, like M’Boundi, Bahr es Salaam, Karachaganak and Wafa.

We actively manage our fields in order to optimize our production performance. Operations are carried out with the application of best-in-class techniques and in-depth knowledge of our core areas, in terms of geology and reservoirs which enables us to be particularly effective.
We are confident we will maintain the current 3% depletion rate for the foreseeable future as well.
The second pillar of our growth during the plan period and beyond is our solid pipeline of start-ups.

400 kboed of our production in 2013 will come from giants that will start up in the 4 year plan.
An additional 160 kboed will be provided by projects of smaller size, which are characterized by their rapid time to market.
Over 240k boed are already in execution. I receive weekly updates and I meet my top management on a monthly basis to discuss their progress, the challenges we face and the solutions we adopt.
The high revenues, coming from our production and contract mix; the low operating costs and the near term growth, result in the highest NPV per barrel in our peer group based on SEC criteria.

Looking at 2P reserves, the NPV remains outstanding.
Based on our price deck of 65$, each 2P barrel is worth a weighted average of 6.4$. At 85$/bl, this value rises by around 40% to 9.1$.
Our goal is not just that of developing our current 2P reserves both quickly and efficiently but also that of transforming the additional 17 Billion boe of contingent resources and risked exploration potential into 2P reserves.
We have proved that we can do this. Almost half of the contingent resources discovered in the last five years (i.e. 4.8 Billion boe) are in projects that are either in execution or already producing.
Our absolute focus on promoting resources to reserves will allow us to target a replacement ratio of 120% for the next four years.
We have a long list of project opportunities in countries where we are already active and able to launch new developments with a short time-to-market.
These opportunities come from many past and recent exploration discoveries in North Africa, Kazakhstan, Nigeria, Angola, Indonesia and the GoM.
Equally, our exploration strategy is focused on adding promising prospects with a possible fast-track to production. Our risked exploration potential today stands at 9 Bboe, of which only 1 is from unconventional plays like shale gas, tar sands and CBM
Over the next four years, we are planning around 190 wells, targeting material volumes in frontier basins in Ghana, Australia and the Norwegian Barents Sea, as well as in the promising theme of pre-salt layers onshore and offshore in Congo, Gabon and Angola.
Our delivery of growth, value and upside will be driven by our new organizational model that, while maintaining a regional focus, brings our best and state-of-the-art competences even closer to our asset base. Production, development and exploration are linked together in a strong and solid matrix that encompasses each business unit to maximise the sharing of competences, know-how and solutions.
This integration means that geographical and technical units share objectives and responsibility on a number of factors, especially regarding production and financial results.

We are able to fully leverage this model because, unlike many in the industry, we have not shifted towards outsourcing through large EPC and global maintenance contracts, striving instead to maintain our core technical competences in-house.
A crucial component of our operations is our attention to HSE.

In terms of safety, our Lost Time Injury Frequency has been reduced by over 40% from 2006 to 2009 and we aim to reduce it further. At the same time, the severity index has been more than halved.

This good performance is partly attributable to our keeping key competences in-house, in particular for the delicate phases of drilling activities, rather than move to a model of massive competence outsourcing.

Our HSE procedures also extend to our contractors. We apply stringent requirements in all the phases of our procurement process and constantly monitor their performance and the standards they apply.
To reduce the environmental impact of upstream activities, we have set ambitious targets on flaring, water disposal and oil spills.
Gas flaring reduction is targeted through re-injection or by identifying effective solutions for its monetization either via the local market or through export routes. In Nigeria and Congo we developed integrated IPP projects to utilize the associated gas from the upstream to satisfy local electricity demand.
This approach allows us to tackle global environmental issues while promoting local development and the creation of domestic markets for stranded resources. By 2013, we target a reduction in gas flaring of 70% compared to the level reached in 2007.
Water preservation is a key issue.
We are reducing the use of fresh water injection by switching to sea water where possible and we are minimizing the disposal of process water through re-injection.
Finally, our oil spill statistics are greatly improving thanks to the massive pipe and tank maintenance and replacement programs we are undertaking.
I will now leave the floor to some of our managers, starting with Antonio Vella, who will take you through our operations.
He will also provide you with an update of our gas conversion factor that has been revised following a re-measurement of the calorific value of our gas production.

Antonio Vella

Thank you Claudio and good afternoon ladies and gentlemen.

The value of our fields is maximised through a dynamic management of our assets, in the sub-surface and on the surface.

This is the philosophy behind our approach to Operations in eni.
The reservoir is the centre of all operations.
We believe that a regular follow-up and proactive management of the field is the only way to maximise recovery, improve performance and generate value.
For this reason, we have moved our reservoir department from the geosciences area to the operations structure.
This allows us to perform a truly dynamic field management.
Through this new organization, we update our reservoir models on a continuous basis so that we can identify new actions and anticipate any issues. Our challenge is to further increase the recovery factor, that today is ***34%*** for oil and ***65%*** for gas. This is already well above the industry average.
Our new projects will benefit from the experience we have gained in our successful history of reservoir management.

Let me give you some examples of our results.

Belayim in Egypt, has been in production since the fifties and is still very important today. Through effective reservoir management and various redevelopments, we have, up to now, produced several times as much as originally expected.
El Borma, in Tunisia, has been producing since 1966 and has an expected final recovery factor of **47%.**
Bu Attifel in Libya has been active since 1972 and we expect a final recovery of **58%.**
Gela, after ***50*** years of production, demonstrates our strength in exploitation of very heavy oil fields. The know how we have gained from operating these fields will be deployed in our new developments - such as Zubair in Iraq and Junin 5 in Venezuela.

That is the subsurface. Now let's move above ground…
The integrity of our surface facilities and assets is essential to guarantee the safety of our people, protect the environment and, at the same time, reach the maximum operating efficiency.
Prevention is the key. We ensure this through regular maintenance, scheduled shutdowns and the continuous monitoring of the performance.
The average downtime of our facilities is ***3%.*** We are committed to improving this figure through close cooperation with our operating companies, introducing new technologies and adopting innovative solutions.
In the case of any unplanned events, we deploy troubleshooting task forces of the most highly skilled specialists to support our affiliates on the ground.
So for us, maintenance is a core competence.
We are further reinforcing this through a policy of in-sourcing, which will gain *us* more direct control over maintenance contractors and let *them* focus on *our* requirements.
On drilling, we are also working on making contracts incentive-based and more rewarding to contractors through safety and efficiency in performance. Through this, and the use of new technologies, we aim to reduce our average non-productive time, already below industry standards, by **50%** in 2010.
We continue to place great focus on R&D, and on drilling in particular. Today, we have 43 patented drilling technologies which have contributed to making our operations safer, more efficient and more effective.
Let me tell you about some of these technologies.
Back in 1994, in order to overcome the challenges presented in Val d'Agri, we pioneered the Automatic Drilling System, which was at that time a revolutionary technology for the industry and now is a standard for all operators worldwide.
With the increase of deepwater activity, we introduced the Dual Casing Run in Angola, Congo and Indonesia. Our lean and extreme lean profiles together with the Eni Circulating Device and Eni Near Balance Drilling technologies have allowed us to drill deeper and safer.
Through these technologies we are now able to safely drill challenging HP/HT wells both offshore *and* onshore. We have done this in Italy, Egypt, Libya, Angola, Gulf of Mexico.
Finally, our achievements in this field have contributed to building the expertise of our company, helping us significantly in the many occasions when we enter new countries.
Our competences in reservoir management and asset integrity become effective through Operatorship.
This is why we assign strategic value to having the leadership on field operations. In fact, we will increase our gross operated production by about ***60%*** to 4 million boed in 2013.
Furthermore, the average opex of eni operated fields are generally lower by ***30%*** versus non-operated ones.
Finally, it is worth mentioning that in order to improve our performance on non-operated activities, we have a dedicated unit focused only on these assets.

Now, before I leave the floor, I'd like to go back to what Claudio said earlier to update you on a technical detail which you will notice in our next quarterly reporting.
In the past 5 years we have started 50 new gas fields.
This had a substantial impact on the average calorific value of our total gas production and led us to launch a complete review of these volumes in 2009.
We are now updating our conversion factor from 6.15 boe per 1,000 cubic meters to 6.36.
This change will be reported in the second quarter of 2010 though it will have no impact on financial results or on production targets.

That is the end of my presentation. Thank you for your attention and I'll leave you to Antonio Panza.

Antonio Panza

Thank you Antonio.

Good afternoon ladies and gentlemen

I will not go through the details of our development projects which will be soon presented by the regional executives.
I'll rather talk about our contribution to growth, our project portfolio , the past performances and the areas of attention to improve efficiency on project delivery. I'll spend also a couple of minutes about projects activities in Italy.
We have a very important task:
to deliver 41 development projects with a total contribution of 560 kboed by 2013. 70% of this production will come through operated projects.
The growth will become evident from 2011 onwards when projects such as Zubair, Cerro Falcone and M'boundi gas will ramp up , while MLE/CAFC, Nikhaitchuq , Samburskoye and others will start production.
The new projects are largely conventional and mainly in areas where eni has a well established presence and experience. [42% of the new production expected in 2013 will come from projects in Africa and 22% from projects in OECD countries.]

Looking at the project category, around 80% of production comes from Onshore and Conventional Offshore. The Angola deep offshore and the artic projects account for the remaining 20%.

As a result, almost 90% of new production will come from projects with low-medium complexity and therefore, from a technical point of view, we don't see any major challenge in delivering most of our projects on time and we are confident we will meet our production target.
One may say that 41 development projects to be delivered in the next 4 years is quite a challenge, but let me remind you that in the last 6 years we have started a total of 54 projects, ensuring an equity contribution of over 540 kboed in 2009 and eni has been responsible for 26 of these projects.

In the same period we also sanctioned further 29 projects, some of which are in execution right now and will ensure a sustainable growth in the coming years.
The integrated structure of our division implies a strict cooperation with both Operations and Exploration to bring resources into production. We are the middle of the chain and have the responsibility of a timely delivery of projects, with the best HSE standards , maximum cost discipline and with a view to their future operational efficiency.

In this context, Operations specialists are involved, together with our engineering staff, from the early stages of concept selection throughout the whole definition process to identify the most effective solutions.

In execution, we carry out a rigorous monitoring of the project through a number of technical Progress Assurance Reviews which are performed on site, in a systematic way and using a multidisciplinary team.

During the definition of our projects, with the aim to optimise time and resources, we use a flexible approach by calibrating the number of sanctioning milestones according to the project complexity and capex amount.

On the procurement side :
we adopt a multiple EPC contracting strategy to favour competition and limit project costs. Some recent examples are Goliat, M'Boundi , Block 15/06 and Zubair;
About rig procurement, we have a fleet of 97 drilling units of which two drilling ships and six semi-sub on long term basis to cover our deep off shore operations in the 4 year plan;
Furthermore, we have finalized two cross country drilling service contracts in order to improve safety standards and reduce costs by keeping the same contractors and working teams on-board regardless of the country in which we operate.
we also make extensive use of Framework Agreements for engineering services and equipment .

Finally, through Standardisation and Synergies we aim to accelerate the time to market and optimize costs.
As example of standardization, in Block 15/06 in Angola, we planned the developments of West and East hubs with a slightly shifted schedule; this allows the combined utilization of part of the project resources, including the management team, installation and supply vessels, contractors and construction yards.
The result of this approach is an optimization of costs and schedule, as we are able to have market leverage by aggregating quantities based on firm commitments plus options for the second development.

At Perla, in the Venezuelan offshore, we are using a standardized approach based on our vast experience on gas projects, both in North Africa (Egypt) and in the Adriatic Sea, where we have similar environment and conditions.
The selected concept is based on the use of pre-developed design such as for tripodes, decks, process and utilities. This will lead to time schedule optimization.
Procurement activities will also be facilitated with the use of framework agreements and experienced contractors.
The original development plan for the MLE and CAFC fields in Algeria consisted of two separate gas treatment plants. However by deeply reviewing the original design of the MLE gas treatment plant, we increased the treatment capacity from 260 MM Scfd to MM 350 Scfd to also accommodate the gas production of the CAFC field.

In this way, by reducing the overall CAPEX of the two projects and accelerating the time to market of CAFC field by at least 12 months, we increased the NPV by around 150 M$.

Kitan is another synergic project where the same FPSO will be used for the sequential development of other assets in the Australia-Timor Leste area.
In this way we optimize tariffs (longer lease compared with a single development) and reduce the mob-demob costs thanks to the proximity of the assets.

Before leaving the floor to the exploration, I’d like to introduce the development activities in Italy that continue to present low cost growth opportunities, leveraging on our established facilities, infrastructure and organization.
Our Italian production will increase in the 4 year plan at a compound rate of about 4.6% , exceeding 200 kboed in 2013.

New production will come from reservoir infilling activities and production optimization jobs in our gas fields of adriatic sea (such as new wells, side-track , workovers, compression facilities upgrade) and from new development projects.

Some of the most relevant projects are :
Val D’Agri Phase 2 development which aims to extend the range of exploitation of the field. The project involves the drilling of 10 wells and the increase of the oil treatment capacity to 125 kbopd.
Ibleo offshore complex which, through the drilling and completion of five subsea wells, will deliver gas, to the Greenstream terminal in Gela, at a rate of more than150 mmscf/d
Let me conclude by saying that capitalizing on our experience, track record and technically low risk portfolio, we are confident we can deliver our projects on time and ensure the promised growth.

Thank you very much for your attention and now I hand you over to Luca Bertelli.

Luca Bertelli

Thank you Antonio.

Good afternoon ladies and gentlemen.
Our mission in exploration is to be the engine of internal organic growth. To achieve this we are working mainly on two fronts:

- First, on creating the “upside” for future growth by unlocking material resources at competitive unit exploration cost; and
- Secondly, on sustaining current production with near field discoveries that can be efficiently tied-in to existing facilities.

eni’s exploration performance in the last 5 years ranks among the best in the industry for discovered resources and unit cost.
The portfolio rejuvenation performed in the period between 2003 and 2007 is delivering results, with material discoveries in the last three years.
Discovered resources in the 2005-2009 period are related for 50% to New Field Wildcat Exploration, of which about 15% in frontier basins, and for 50% to Near Field and Appraisal activities.
During the last 5 years, 4.8 Bboe of contingent resources have been discovered through exploration.
Today more than 40% of these volumes are in Projects already producing or in execution. The remaining are in the pre-FID phase or in the appraisal evaluation phase.
Exploration is working continuously to reduce time to market performances and we have set ourselves ambitious targets for the next 4 years.
The objective for 2013 is to increase resources in production and execution to 50% by improving the time to market of the exploration process significantly.
This will be achieved through a more efficient integration between ourselves, Development and Operations.
We aim to reach a balance in exploration capex allocation, with 70% devoted to support production in the near and mid terms and the remaining dedicated to frontier basins.

Near Field Exploration, mainly carried out in our legacy areas, aims to elongate the production plateau of producing fields by connecting their satellites.
Proven Basin and Plays, represent those areas where we have a consolidated presence and know how, both on geology and reservoirs. This is mainly conducted in: Deepwater Angola and Congo in post-salt plays; the Norwegian Sea; Indonesia deepwater (Kutei and Tarkan Basins); and deepwater Gulf of Mexico.
Finally, 30% of capital will be allocated to frontier exploration basins. Here, we target material volumes around which to create future giant opportunities. If compared to the past, efforts devoted to these basins and new plays are growing of importance, with the objective to unlock those resources that could drive long term growth. Lets have a look at where they are.
In Africa, the transform margin basins in the Gulf of Guinea (Tano Basin in Ghana), the Rovuma Basin in Mozambique and the pre-salt frontier in Gabon offshore and onshore.
In Far East, the deep water of the Carnarvon Basin in West Australia as well as the Timor Leste and Timor West deepwater plays.
In Europe, the largely unexplored Barents Sea where we have a leadership position with the first artic oil project under development (Goliat field).
In South America, the Maracaibo offshore Gas Basin.
It is through this exploration that we aim to "unlock" giant upside. Last two years proved that the strategy is paying off with the discovery of Perla in the Maracaibo gulf, whose recoverable reserves are currently estimated in over 9 tcf.
The overall potential of our exploration portfolio is estimated at about 9 Bboe including the potential in Unconventional, which I will now take you through.
Eni is not big in unconventional, however we are involved in all main unconventional plays with a total net resource base approximately of 1.5 billion boe, which represents roughly 15% of the overall exploration portfolio upside.
Let me highlight some of the initiative we have undertaken:

- The Gas Shale Alliance with Quicksilver in the Barnett Shale where we already produce at an equity level of 6000 bbld;
- The Indonesian CBM Project (Sanga Sanga);
- The West Africa Tar Sands Pilot Projects in Congo;
- The exploitation of the Tight Gas upside in our Pakistan ventures.

So as previously mentioned eni exploration is still mainly based on conventional resources. We are however active in all the main unconventional plays where we expect to grow in the future.
Eni is investing significant resources in R&D to improve petroleum system modelling and to de-risk exploration.
Cutting-edge distinctive technologies have been developed in these years that are now positioning eni as the best in class in some geoscience sectors. These proprietary technologies have also significantly contributed, on several occasions, in presenting ourselves to NOCs of new countries we were looking to enter.
I would like to highlight:

- The package for Petroleum System Modelling, which are systematically used in the evaluation and assessment of exploration potential of new acreages and to rank prospects in defined exploration areas.
- The package for in-depth imaging that are utilised to unlock material resources in complex geological settings such as sub-salt, sub-basalt and sub-thrust exploration. This package in particular, was the key to exploration hits in Block 15/06 in Angola, where we achieved a rate of 80% of success during the first phase of the exploration campaign.

Thank you for your attention. I will now leave the floor to our executives in charge of the geographical business units.

Guido Michelotti

Good afternoon ladies and gentlemen.
Let me share with you some highlights on one of our core regions.

North Africa groups most of the countries which represent the roots of eni's successful conversion from a small domestic player into a major integrated oil company and which still significantly contribute to its industrial performances. Every third barrel of our equity production comes from these countries.
Throughout the years we consolidated our position in the region and today we are the leading producer with an operated production of 1.17 millions boepd and an equity production averaging at about 600 kboepd; 49% of this production is gas.
Our mid term objective is to maintain production at the current level notwithstanding the maturity of most of our assets. We will achieve this through a combination of production optimization and greenfield projects, which will compensate the natural decline.

- One of the most important greenfield projects in North Africa is the MLE/CAFC in Algeria. eni has been present in Algeria since 1981 and today we are the number 1 producer in the country, with an equity production slightly lower than 80 kboed, 50% of which is operated.

- The combined MLE-CAFC development is a giant project with reserves of nearly 600 million boe and a plateau production of 120 thousand boed.

- As Antonio Panza has anticipated, we plan an integrated development of the two fields, with common infrastructure such as the gas plant, the airstrip and the export pipelines. Their construction as well as the preparation of the site for the Central Processing Facilities has already started. 38 wells out of 92 have been drilled.

- Start up for MLE is planned in November 2011, a very tight and challenging schedule as it means only 32 months from the EPC contract award to first gas, while the EPC contract itself has a 36 months reference schedule. Oil production from CAFC will come on stream one year later, in December 2012.

In Egypt eni is also the leading producer with an equity production of 230 kboed in 2009. Last year we signed an agreement with the Government to increase and widen the scope of a 50 year long cooperation, including the extension of the Sinai leases till 2030.

We have three main strategic objectives in this country:
First, to mitigate the decline of our legacy giant oil fields through the use of innovative technologies. Production decline is being managed by application of new technology and I would like to mention two of them: radial drilling and improved displacement efficiency.
Secondly, we will complete the development of our discoveries in the Nile delta off-shore. 5 new fields, 3 of them operated, will come on stream by 2012 thus adding nearly 20 Mm3/d of gas production and 350 Mboe of reserves.
Finally, we will refocus exploration activities, targeting deeper layers in the Western Desert and potential new themes in the Mediterranean. Results of first deep wells in Western Desert are encouraging and we are confident we have the key to unlock the remaining prospectivity.
Let me now briefly comment on Libya and the Western Libyan Gas Project. It is the biggest project in the Mediterranean Sea, a combination of off-shore and on-shore development and subsea export pipeline across the Mediterranean Sea which started producing in 2004. The project currently

delivers approximately 10 BCM per year of gas, 80 % of which is for export, 35 kbpd of oil and and 61 kbpd of condensate, for an aggregated average production in excess of 300 kboepd.

Notwithstanding this large scale, the drilled wells and facilities installed represent only the first phase of development. **We still have approximately 1.5 billion boe of discovered reserves to be developed** in the coming years to meet an increasing domestic demand, as well as to capture additional export opportunities.
The timing of this second phase is subject to market dynamics. The currently low gas demand in Europe and the large availability of cheap spot cargoes are slowing down some gas development projects as well as some production, such as our Libyan one.
We remain confident that the demand will rebound in the medium term. This project will therefore substantially contribute to our long term upside **through the development of 2 more giant fields** and a string of other minor that (i) will extend the current production levels for the entire duration of the Gas Sales Contract and (ii) increase overall gas sales from 10 to 16 BCM per year.
So, to conclude. Our position in North Africa is still very strong. We are successfully fighting decline on our fields with new technologies, progressing rapidly on new giant developments and actively working on the large resource potential we have already discovered in the region.
Thank you and now I hand you over to Roberto.

Roberto Casula

Thank you Guido, good Afternoon Ladies and gentlemen,
I will share with you some aspects of **eni** activities in the Sub Saharian region.
eni has been present in the Sub saharian region for decades benefiting from excellent relationships and a solid reputation.
One of the leading characteristics of the region is its growth potential: in 2010 we are scheduled to produce (from Nigeria, Congo and Angola) over 420,000 boepd representing a 15% increase compared to 2009 alone.
During the last decade the Region raised its oil & gas production by 5.4% and going forward in the next 4 years, prospects are ever better with an expected growth rate of 10%.

One distinct element for us in the sub-Sahara is a presence in all of the major gas projects as part of our unquestionable leadership in the utilization of gas resources. It includes the participation in 6 Trains in Nigeria LNG, a lead role in the upcoming Brass LNG, partnership in Angola LNG, technical leadership (jointly with Sonagas) in the Angolan Gas Project aimed at further expansion of the Soyo plant through the exploration and development of additional gas resources.

A special mention should be made [to] of the successful utilization of gas for power generation. In both Nigeria and Congo we built power plants generating in total 850 MW as part of our gas flaring down program.

These achievements are key to the success of eni's cooperation and sustainability model: a model that combines the industrial base of our business with initiatives supporting the growth of our host countries in fields such as infrastructure, development of unconventional oil resources, health, education and training.
Nigeria continues to play a major role in our plans due to the magnitude of our organization there, related level of investments and its highest contribution to our expected daily production.
Currently the industry in Nigeria is facing major challenges. Today I wish to focus on two of them namely, the Petroleum Industry Bill, the P.I.B., and Security related issues.
As to the P.I.B., let me say that its major reform objectives, such as the improvement of the legal framework and of the efficiency in the oil & gas sector, are certainly endorsed by all the Oil

Companies. How do matters stand today? : Out of the several versions that have been circulated over the last few months, the most recent Senate one is presently at the top of the legislators' agenda. In it, there remained, still, some unresolved issues. There are no doubts, however, that this version is by far superior to the earlier ones. Several gaps were closed, some form of grandfathering is included and we continue to remain confident that the open approach adopted by the Nigerian Authorities will allow the Industry to further elaborate and, hopefully, improve the final terms. Whether this bill will become law before the next election is difficult to assess.

Another key challenge to our Nigerian activities is the Security issue in the Niger Delta. The post-amnesty situation is certainly much improved with risk level limited to small and medium groups of criminals.

To address the issue, our strategy is to continue enhancing the relationship with the communities and evaluating specific technologies suitable to monitoring the pipelines networks.

However, and we cannot hide the fact, a degree of uncertainty in the area may yet present a risk of disruptions to our operations. We are therefore carefully evaluating all other opportunities still available offshore, whether in conventional or deep waters.

Moving on I would like to focus your attention on two key projects in the area: Mboundi in Congo and Block 15-06 west hub in Angola.

Mboundi represents, without a doubt, one of the most important onshore fields in Africa and furthermore a strategic project for **eni.** As you can see, the magnitude of this project in terms of investment, reserves, production and [the element of] power generation, places it among the main projects in our portfolio.

Mboundi project contains three clear segments [namely]: oil, water and gas.

Let me start by addressing **Oil** :

We are sustaining the field oil production through new wells, works-overs, pumps and facilities upgrade \ enhancements to aligning technical designs and HSE elements to international standards.

Water:

Water injection is essential for this reservoir in order to offset the pressure depletion. Just recently we have completed the installation of a pipeline from the coast shore to the field. A temporary seawater intake and pumping station is now sending 120,000 barrels a day of sea water thus ending the drilling of the onshore source wells and production of fresh water. These wells will be handed over to the local communities for their consuming needs.

Gas&Power:

When we took over field operations, almost 5.5 to 6 million cubic meter of gas were flared daily. Our immediate action was to shut in the high GOR wells thus lowering the flared gas to half of its previous volume. Furthermore, we commenced discussions with the Republic of Congo on how to make of use of this gas // resulting in a 300 MW **Power Project** that is currently under execution. Actually, the Power Plant is already in operation and we expect to complete all the works by October this year.

You can easily ascertain the value of the project in terms of sustainable development: on one hand the main towns and villages will enjoy a stable access to electricity while, on the other, electricity is a key driver for industrial development.

Let's now turn to Block 15/06, in the deep waters offshore Angola, a Block awarded to Eni in 2006 following a highly competitive international bid process.

Exploration in Block 15/06 has been effective thanks to our deepwater expertise and the use of our technologies which improve the overall success rate and optimize both time and costs in well operations.

The Initial discoveries were Sangos-1 followed by N'Goma-1 in 2008 and Cabaça Norte-1 in 2009. In 2010 we had additional discoveries such as Nzanza-1 and Cinguvu-1, and particularly the recent discovery of Cabaca South East which further affirm that the potential of Block 15/06's results are within, and in some cases exceeding, the predicted hydrocarbon volume ranges of pre-drill expectations

I emphasize the exploration activity not only because it generated successful results but also to highlight that we are completing the committed work program well ahead of the stipulated contractual terms. Among the various companies awarded a deepwater block in 2006, we are certainly noticeable for our fast tracked exploration activity.
In similar fashion, we are currently proceeding to the development phase. The discoveries thus far can be assembled in two separate hubs, western and eastern.
As Claudio already highlighted, time to market is imperative for Eni hence we are heading towards the Final Investment Decision of the Western Hub within the fourth quarter 2010 with anticipated first oil by late 2012. Development will commence by targeting the two discoveries of Sangos and Ngoma moving then to the extended satellite structures of N'zanza and Cinguvu.
Simultaneously, due to the significant discovered reserves, we shall fine-tune our design, engineering and contractual solutions placed for the Western Hub project to allow the Eastern Hub to be ready for sanctioning as early as the first quarter 2011.
We are confident and eagerly det**e**rmined to implement the above plan as part of our wish to play a major role as Operator in Angola, strengthen **eni**'s already solid position in the country and further enhance the existing and excellent relationship with Sonangol.
I trust my short account, has given you a flavor of the measure of activities currently on-going to boost the impressive growth **eni** enjoys in the sub-Saharan region.
I thank you for your kind attention and I pass you on to Marco.

Marco Alverà

Thank you Roberto.
Today I will focus on our two new projects in Venezuela,
and our 3 artic projects in Norway, Russia and Alaska.
We will start with Venezuela, which we consider the latest country where the so-called "eni model" has been applied.
After the start of an international arbitration on Dacion, we obtained a good monetary settlement in 2007.
As part of that settlement, we included an exclusive right to perform a development plan and reserve certification for Junin 5.
That exclusive right is paying off.
After two years of high pace work with PDVSA, both activities have been completed and we signed the Junin 5 agreement in January.
Just as we were thinking (with some concern) about the large volumes of gas needed for Junin's Refinery,
we discovered the huge Perla gas filed.
Perla and Junin have the potential to bring or net production from Venezuela to over 170 kboed within this decade.

Lets go into the details of these two giant developments, starting with Junin.
Ryder Scott certified that the Junin 5 Block holds over 35 Bboe of oil in place,
of which we expect to recover 2.5 billion over 40 years.
In the nearer term, the reservoir characteristics are such that we plan to sustain the plateau of 240 kboed for 14 years without recourse to steam or other enhanced oil recovery techniques.
At the beginning of next year we will sanction the Early Production of 75 kbbl/d.
The cash generated by the early production will help finance the refinery, that we will build for the full field development.
Our refinery will be built on the last remaining plot available in the Jose industrial complex right on the coast.
This location is a very attractive feature of Junin 5.

The other projects in the Orinoco belt, will have their upgraders built in a remote region, far from the coast, where there is no infrastructure at all.
We will sell refined premium products internationally, in hard currency, and our refinery profits will be taxed at an attractive 34%.
Overall, we expect to drill a total of 1500 wells only 500 m deep, with a lateral displacement of 1500m.
Junin 5 is a very conventional upstream and refining development.
The project has solid economics with a breakeven price around 50 $/bbl.

Moving to Perla…
Perla is a true gem in our portfolio.
Potentially it's the largest gas discovery in South America, with well over 9 tcf of estimated reserves.
The exploration strategy behind this find is precisely that outlined by Claudio earlier: amid a relatively conservative probability of success, before drilling we knew that the possible volumes were giant, and that the gas could quickly be sold to the domestic market.
Perla is a concession with royalties at 20%, income tax at 34%, and a licence term of 30 years.
We target FID for early production by the end of this year, with startup at the end of 2013 in less than 3 years since discovery.
Initial gas will go to local refineries that are just 50 km away and are currently burning oil because they have no gas!
The full field development could reach a plateau of 1.2 billion cubic feet per day.

Perla's full field breakeven price is currently estimated at below 3 $/MMbtu.

This low breakeven gives us multiple commercialization options.
Though we're not ruling out any export alternatives, the local market may turn out to be a more profitable option.
In fact, although potential gas demand in Venezuela is about 6 bcf/d, consumption is only 4 bcf/d.
On top of the current deficit of about 2 bcf/d, Venezuela also has an agreement to reverse the flow of it's import pipeline, and start exporting gas to Colombia from 2012. Furthermore, demand is expected to increase 40% by 2013.
In this relatively tight market, our first option is to use Perla's gas in Junin's refinery, which will consume between 200 and 400 mcf/d, depending on which upgrading technology we use.
This would be like converting gas into refined products such as diesel and exporting it at very high prices per unit of energy.
We also see opportunities to sell gas in Maracaibo and Jose, for oil recovery and to feed new industrial complexes and power stations that are being built.
As a reference, we know that gas is currently being bought in the Venezuela at prices significantly above 3 $/MMbtu.

We are confident that we will extract significant commercial value from Perla.

Let's now change climate and move to our activities above the arctic circle.
Most geologists would agree that the largest potential for the Oil&Gas industry lies in this region.
The USGS estimates that the Arctic as a whole has over 400 billion boe still to be discovered.
Eni is the only company currently operating in the Barents Sea, on the North Slope in Alaska and in West Siberia.
Our Artic strategy is no coincidence: we started operations in Norway in 1965.
In Russia, we have been buying gas from the Novi Urengoy area for more than 40 years and have had a strategic alliance with Gazprom since then.

In the Arctic region we operate onshore, offshore and in mixed on/offshore projects facing all the difficulties of the arctic environment: fragile local communities and economies and extreme environmental conditions and sensitivity.

On average, our artic projects have a breakeven of approximately 45$/boe

Let’s have a closer look at these projects, starting with Goliat.
Goliat is the key project being developed in Norway right now.
It will be the first oil development in the Barents Sea and will have the first manned offshore facility in the entire Arctic.
Goliat was sanctioned at the end of last year, after we were able to capture and lock in the lowest costs in the market downturn.
In January, we awarded the construction of our unique circular fully winterized FPSO to Hyundai, following a very competitive tender process.
Development is well underway: we are receiving excellent support from the Norwegian Government, the local communities in Hammerfest and from our partner Statoil.
Together, we are implementing the best in class response and support procedures.
New technologies to detect oil spill in darkness are combined with a very unique stand by vessel as well as intervention plans involving most of the local communities.

The project breakeven is just below 50$ per barrel excluding likely upsides coming from selling the gas that we plan to re-inject, and from using the spare capacity in the FPSO to produce future near field developments.
Let’s move east across the boarder to Russia.
As you know, last year Gazprom exercised both call options to buy 51% of Severenergia and eni’s 20% in Gazpromneft. We have received 5B$ in cash and our upstream exposure in Russia is now limited to 750 M $.
Severenergia has 5bnboe of 2P reserves among 4 main assets.
The fields sit right at the heart of Gazprom’s gas networks, and are among the last, relatively simple and inexpensive developments in the Novi Urengoi area. Also for this reason, Gazprom and the Russian government are fully committed to their fast development.
Based on the terms of the newly approved licences, all Severenergia fields will be in production by 2018, with total volumes in excess of 500 kboed, of which 165 thousand net to Eni.

Samburskoye is the most advanced of the fields, with facilities 80%, and start up in 2011.

The regulated gas price in the area is currently 43 $/thousand cubic meters, which is well above the project breakeven.
Furthermore, domestic prices in Russia are widely expected to grow.

Now crossing the Bearing Strait into Alaska…
Nikaitchuq is our main project in Alaska.
The processing and utilities modules have been built in Louisiana for cost purposes.
These huge facilities have been loaded on barges and have left harbor last week.
They will sail through the Panama canal and all the way up and around the west coast to arrive on the Slope in Alaska in August. First oil will flow in January.
Overall we will drill 52 wells from an onshore facility and from an artificial island we have already constructed.
As with Goliat, the facilities are built with spare capacity for future discoveries and for the adjacent Ooguruk field, where eni has 30%.

Even without any upsides, the project economics are very solid also thanks to the favourable tax treatment on CAPEX in Alaska.

We are aggregating experiences and best practices in our arctic developments to benefit our current projects, but also, and more importantly, to build the skills, the track record and the confidence to be ready to participate in new artic developments in the future.
After all, our experience in operating in cold environments comes a long way, having entered Kazakhstan in 1992 with Karachaganak.
Thank you for your attention.
I will now leave the floor to Massimo.

Massimo Mondazzi

Thank you Marco.
I will now take you through our key projects in Kazakhstan and the Far East, starting with an update on Kashagan.
The field, currently estimated to contain 35 billion barrels of oil in place, is the world's most important oil discovery in the last 3 decades.
As you well know, in 2009 the North Caspian Sea Consortium adopted a new operating model and the operatorship has been assigned to the North Caspian Operating Company.
Eni remains in charge of the Experimental Program and the onshore portion of the Phase 2.
Execution of the Experimental Program is progressing with a sizeable step-up in the activities and recorded manhours, which increased by 38% in 2009. At the end of April the overall progress of Experimental Phase reached 82%.
The EP execution includes:

- Offshore processing facilities on the 1° artificial island;
- 5 drilling islands from which 40 wells are being drilled (20 of these wells have already been completed with an estimated potential of 400 kbbl/d);
- Interfield sealines and pipelines;
- Onshore facilities for final processing of crude and sweetening of the raw-gas.

Phase 2 on the other hand is currently in the stage of Front End Engineering Design; part of the current engineering activities are focusing on assessing cost optimization opportunities.
Let me now focus on our expectations from Far East/Pacific regions.
Our position in Far East is smaller compared to other legacy areas. Equity production reaches a total of around 60kboed from Australia, Indonesia and China. Half of this production is related to the LNG project of Bontang and Bayu Undan.
We are now close to a material enlargement of our presence in the region, with almost 500 million boe of discovered resources in the Kutei basin that will become soon a new project of supply to the Bontang LNG plant.
Moreover, in the next two years we are going to explore a large potential in the Carnarvon Basin as well as in the JPDZ and the Timor Leste areas. We estimate more than 1 bn boe of eni net risked volume related to these areas.
Finally with our CBM project in Indonesia we will launch the first "CBM to LNG" in the world.
As a result, our equity production in the region could significantly increase in the next future, depending on the success of the exploration campaign to be carried out on existing resources.
Lets focus on our 2 major development projects currently ongoing, starting with Kitan.
eni successfully drilled the Kitan 1 exploration well in January 2008, which was closely followed by an appraisal in March 2008.
The Kitan oil field is located in the JPDA of the Timor Sea, an area jointly administered by the states of Timor Leste and Australia. The final development plan was formally approved by the Authority in April 2010.

As mentioned by Antonio Panza, the development concept is based on a stand alone dedicated FPSO which will process the oil flowing from three vertical wells with subsea completion. The 2P reserves associated with the project exceed 30 Mboe.
First production is expected in the second half of 2011, just over 3 years after the declaration of commerciality, while peak production capacity of 40 kboed will be reached one year later.
To date, most contracts have been awarded and the estimated break even price is around 40 $/bbl.
We see a significant upside in the area of Kitan, as the acreage is highly prospective. Overall (unrisked) exploration potential is in the range of 300 million bbls.
A dedicated drilling campaign is about to start with the aim to verify the possibility of additional stand-alone developments or to exploit the synergies with the ongoing development.
Now on our CBM development.
Today eni has a 37.8% interest in the Sanga-Sanga CBM block, located in the Kutei Basin Onshore-East Kalimantan, which is operated by VICO CBM, a company jointly owned by eni and BP.
The presence and the distribution of prospective coal layers has been confirmed by 800 wells drilled in the area since 1977. The resources associated to these coal beds are estimated in 5 TCF. An additional potential in the range of 5 Tcf is expected to be present in the deeper horizons.

Sanga Sanga CBM project will be developed in phases over a period of nearly 20 years. Peak production is expected in the range of 500 million Scf/d after 2016 and in line with PSA terms, 25% of the gas production will be sold on the local market, while the remaining 75% will be destined to LNG via Bontang. Capex are expected to be in the range of $1 bn net to eni.
This CBM to LNG project will benefit from the synergies offered by the existing facilities and the spare capacity in Bontang plant, with a short "time to market" and low unit development capex.
Thank you very much for your attention, I will now leave you to Claudio.

Claudio Descalzi

Now I'd like to take you through our progress in Iraq.
Zubair field has been producing since 1951 but it still has enormous potential. With only 7% of the estimated original oil in place having been recovered, we aim to reach a final recovery factor of about 34% in twenty years.
The production comes from 3 main reservoirs with different API oil gravities with an average of around 30.
The field is currently producing around 180 kboed from 70 of the 182 wells.
During 2010, the field will be operated by SOC, the Iraqi state company under a close supervision of our team based in Zubair
Operations will be taken over in 2011 for the duration of the contract.

About 20 of our people has been in Iraq since the beginning of February 2010 and we expect to reach a permanent presence of about 115 by the end of next September.
The Interim Work Program and Budget was approved on March 20th, 2010. This will cover all the activities to be performed with an aim to reach the 10% threshold over the Initial Production Rate by the end of the year, allowing us to start cost recovery.
Our immediate target is to maximize the use of SOC existing contracts through 2010. 2 drilling rigs and 3 workover rigs are presently operating in the field and we plan to add 4 drilling rigs and 4 workover rigs.
The Rehabilitation Plan was submitted for approval on April 15th and is expected to be approved shortly. The plan will be implemented within the first 3 years of the contract.
We are currently issuing competitive tenders for all activities foreseen by the Rehabilitation Plan.
So far, a total of 10 tenders have been launched: among them 3D seismic acquisition, HSE baseline study, ESP system, drilling, workover and rigless activities.

The Enhanced Redevelopment Plan will be prepared during the first 3 years and implementation will start in 2013, aiming to reach production plateau of 1.2 Mbbld within 6 years and to maintain it for 7 years.
Just to give you a few details, between 2011 and 2020, we will:

- Drill 256 wells and 129 water injector wells
- Refurbish existing facilities to recover about 90% of total oil treatment capacity
- Build a new power plant
- Lay about 1600km of oil and water flowlines

I hope this section on our major development projects has been interesting and useful in helping you understand how we are progressing with delivering our growth. Let me now recap on the main topics we covered today and wrap up the afternoon with some closing remarks.
Looking ahead, conventional plays will continue to be the main pillar of our growth and development.
Eni is well positioned to deliver production growth at attractive costs thanks to its focus on conventional hydrocarbons in the world’s fastest growing oil-producing regions. In particular, we are focusing on plays such as pre-salt layers of West African basins, onshore and offshore.
We have been the pioneer of the domestic gas valorization, through developing gas power plants and upstream integrated projects.
Through this approach we will be able to consolidate and increase our presence in Africa and this will be more and more a key formula in the future.
In terms of unconventional plays, we see some emerging themes, such as shale oil/gas, tar sands and CBM, for which we aim to find an application in our core areas as we know that this is where we will be able to create real value.
On shale gas, we have acquired knowledge and expertise through our JV with Quicksilver in the US Barnett shale. This expertise will find application in North Africa and Eastern Europe.
Meanwhile, tar sands are a promising theme in West Africa, where we already have a pilot project in Congo.
Finally, we are confident that our CBM project in Indonesia, combined with the gas discoveries in Carnarvon basin in Australia and in the Timor areas, will open up opportunities to build a stronger LNG position in the Pacific area.
Ladies and gentlemen, we have come to the end of our presentation.
I hope we have given you a clearer perception on the value of our resources and our strategy to ensure timely and cost-efficient production growth.
Our new organisation will be a key driver in the delivery of our plan and targets. This will enable us to leverage and exploit eni’s distinguishing characteristics:

- Our strong competence base, which we have built and maintained in-house.
- Our focus on execution and problem solving capabilities.
- Our strong sense of belonging and engagement.

Our assets, our organisation and our people are the reasons why I’m fully confident that we will deliver growth and value over the plan period and beyond.
Thank you for your attention.
Now, together with our CFO Alessandro Bernini, we will be ready to answer to your questions.