PAO NOVATEK

Third Quarter 2016

Financial and Operational Results – Earnings Conference Call

28 October 2016
Moscow, Russian Federation

Ladies and Gentlemen, Shareholders and colleagues good evening and welcome to our Third Quarter and Nine-Months 2016 earnings conference call.

It's a pleasure this evening to formally introduce Alexander Nazarov, as the new Head of Investor Relations for NOVATEK. Many of you may already be familiar with Alexander from his former role as an oil and gas analyst with Gazprombank. We welcome him as part of our team and I am sure you will have the opportunity to meet with him at investor meetings as we continue our ongoing efforts to provide timely and informative information to the investment community.

DISCLAIMER

Before we begin with the specific conference call details, I would like to refer you to our Disclaimer Statement as is our normal practice. During this conference call we may make reference to forward-looking statements by using words such as our plans, objectives, goals, strategies, and other similar words, which are other than statements of historical facts. Actual results may differ materially from those implied by such forward-looking statements due to known and unknown risks and uncertainties and reflect our views as of the date of this presentation. We undertake no obligation to revise or publicly release the results of any revisions to these forward-looking statements in light of new information or future events. Please refer to our regulatory filings, including our Annual Review for the year ended 31 December 2015, as well as any of our earnings press releases and documents throughout the past year for more description of the risks that may influence our results.

CONFERENCE CALL TEXT

For tonight's call, I will not discuss the macro environment as I believe this topic has been exhaustively covered by the press and industry analysts following OPEC and their discussions. Instead, I will provide an update on Yamal LNG as well as addressing questions raised on production declines. I believe these two points are more relevant for us this evening.

Construction on the Yamal LNG project moves forward according to our proposed schedules. We made good progress on the project's construction phase and as of 30

September we were 69% complete with the total project construction versus 60% at the conclusion of the second quarter, and we have now completed 84% of the LNG train #1 versus 76% in the second quarter. All of the main equipment for LNG train #1 is currently onsite, so we do not anticipate any impediments to reaching our target completion rate of over 90% by year-end.

There are more than 22,000 construction workers currently working onsite (versus 16,500 at Q2), with an additional 29,000 people involved in module fabrication at various construction yards around the world. As I had stated previously Yamal LNG is a huge undertaking with over 220 contractors involved in the project as well as more than 3,600 construction vehicles presently on site.

We began using two (2) new cargo berths at the Sabetta seaport, so currently there are six (6) cargo berths in operation as of the fourth quarter. The ability to utilize a full complement of cargo berths facilitates the landing and unloading of modules to the project site. On a prior conference I stated that LNG train #1 consists of 78 individual modules. As of the beginning of October, 70 modules have been delivered and the remaining eight (8) modules are in transit, of which three (3) modules are expected to land this week. The high proportion of module delivered account for the high project completion percentage for LNG train #1 and we expect all remaining modules for LNG train #1 to be delivered by year-end. The liquefaction module with a weight of 5.8 thousand tons was delivered in September and installed on its prepared foundation. With this key unit in place, we were able to install the main cryogenic heat exchanger delivered by Air Products inside of the liquefaction module in early October.

In the third quarter, we completed the drilling of an additional eight (8) production wells and presently have 65 production wells drilled, exceeding the required well stock of 58 production wells to operate LNG train #1. In addition, the construction of the gas gathering lines for LNG train #1 is being finalized and should be completed by the end of this quarter.

There are a series of "other" ancillary construction activities ongoing at the project site at various stages of completion but I don't want to spend too much time this evening on them except to highlight that all three (3) 50,000 cubic meter gas condensate tanks for the project were completed and passed their hydraulic tests and that substantial work progress has been made on the two (2) kilometer South-Eastern ice barrier wall used to protect the harbor and loading operations.

I've been asked many times recently at investor meetings about the production declines at our core legacy assets and that possibly NOVATEK is ex-growth in its operations. Related to this question we have also seen more analysts convey this message to investors in their research reports despite the fact that I mentioned on my last conference call that this was not the case in our estimation based on our asset portfolio and the projects that we are currently assessing. So, I would like to

now shift my conversation to this important topic before discussing the financial results for the period.

Natural declines in hydrocarbon reservoirs are a well-known fact once the field's production output reaches its planned plateau levels. So this fact should not come as a surprise to anyone following the oil and gas sector. In our specific case, we have reached our plateau levels on our various fields at different times based on the start of the particular field's operations and development plan. For example, our three (3) core legacy fields, which are exhibiting natural declines, began commercial production in 1998 for the East Tarkosalinskoye field, 2002 for the Khancheyskoye field and 2003 for the Yurkharovskoye field. All three (3) of these legacy fields have reached their plateau levels and are now experiencing varying rates of declines due to natural declines in reservoir pressures, but let's not lose sight of the fact that we have achieved substantial cumulative production from these fields and will so for many more years consistent with their respective license terms.

So, to answer everyone's concerns, yes, our production is in various stages of natural decline, but we are not alarmed by these recent developments. Instead, we seek efficient ways to optimize our field's production output, new producing zones within our current license areas or pursue new exploration and development opportunities existing within our present asset portfolio. This high-grading process also extends to our review and potential acquisition of new licenses areas to complement our existing portfolio as well as through potential property or corporate acquisitions if we feel these opportunities are value accretive to our shareholders and fit our strategic objectives of maximizing our "wet gas" value chain.

I would like to highlight a specific example of how we optimized one of our core development plans. If we consider our largest producing asset – the Yurkharovskoye field – we utilized a four (4) phased approach to reach the field's production plateau as well as making significant design changes to optimize production outflows. We reduced the total number of wells needed to drill this prolific field from the initial well count of 88 production wells to 79 production wells by significantly increasing the wellbore diameter from 114 millimeters (mm) to 168 mm, a deviation from 2,000 meters to an average of 3,500 meters, and horizontal runs from 500 meters to over 1,000 meters to extract more gas and gas condensate from the multiple producing zones within the Valanginian formation. As a result of these design changes, we managed to significantly increase our initial daily output from roughly 1.2 million cubic meters (mcm) to about 5.5 mcm; thus reducing the average drilling cost per mcm of cumulative production from $2.72 per mcm cumulative production to $1.64 per mcm, representing a savings of about 40%.

We also increased flow rates above our planned maximum output at the Yurkharovskoye field around 2013/2014 to maximize stable gas condensate production to help finance our proportion of the Yamal LNG costs pre-external financing but subsequently reduced the field's outflow back down to its current

planned production levels to efficiently manage the field's plateau production. I previously highlighted this point on a prior conference call but I wanted to reiterate this point again tonight as that decision affected the future decline curve for the field. It was a decision that we felt was best suited to achieve another strategic goal of transforming our operations by investing capital into Yamal LNG.

To offset the field's natural declines, we are currently drilling well #135 on the West Yurkharovskoye field, which flanks the eastern portion of the Yurkharovskoye field as part of our exploration drilling to test the Jurassic formation at this license area. Well #135 was drilled to a vertical depth of 4,400 meters with a planned horizontal run of 500 meters. We are now preparing the well for the horizontal section and will utilize a four (4) stage hydro-fracturing process to determine potential commercial flow rates. Well logging was already completed on the Valanginian formation as part of our planned work but we still need time to assess the potential commercial production at the Jurassic formation, which is anticipated to be completed by the end of the first half of 2017. Our initial assessment at the vertical depths looks promising but it is premature at this time to provide any concrete conclusions until we have concluded the horizontal section and the appropriate testing.

A successful conclusion would provide us with additional geological subsurface information regarding the possible extension of the Jurassic formation across the Yurkharovskoye field, essentially meaning that we could potentially extend this field's production profile if deemed economically viable to justify the implementation of a new development plan. So, I will provide additional information on future conference calls and investor meetings

I would now like to discuss our ArcticGas assets because we have fielded a series of questions on this joint venture particularly concerning the field's oil development program as well as other questions.

The main goal of our development activities at Arcticgas, formerly SeverEnergia, was to maximum the various fields' gas condensate production. We took this approach because of the high concentration of liquids grams per mcm produced and this development approach allowed us to reach the maximum load capacities at the field's gas and gas condensate de-ethanization treatment facilities as well as fully loading our own Purovsky Processing Plant and the Ust-Luga facility.

If we focus specifically on the Urengoyskoye field, considered the main producing asset of the joint venture, the new wells drilled and completed in 2016 reached daily well flows of 1.3 mcm of natural gas and up to 500 tons of gas condensate. These new wells were drilled in the northern part of the license area with low reservoir properties in the Achimov layers containing a very high gas condensate factor. The high flow rates we have achieved – particularly pertaining to gas condensate – allowed us to reduce our drilling activity to a minimum, and presently we have only one drilling rig in operation. Overall, in the 3Q 2016, our production of gas

condensate was relatively stable but production of natural gas was slightly lower primarily due to the higher concentration levels of gas condensate. That was our planned development objective and fully anticipated.

To give you a sense on how we maximized the Urengoyskoye field development I would like to reiterate a few points I made on one of my earlier conference calls. In 2013, we changed the development program from primarily drilling vertical wells to drilling horizontal wells with horizontal sections averaging approximately 600 meters in length. The initial flow rates from the horizontal sections exceeded by two times the flow rates of vertical wells depending on the length of the horizontal sections which led us to optimize our drilling program by reducing the number of wells drilled from 136 to 96. I stated at the time that the average horizontal well costs were approximately 20% to 30% more capital expenditure per well drilled but the additional flow rates and the reduction in the total well stock easily justified this decision.

We don't have analogues in Russia or globally to compare the results of our Achimov wells drilled at the Urengoyskoye field with horizontal sections ranging from 1,500 to 3,000 meters in abnormally high pressure using multi-stage fracturing. From our discussions with drilling companies and technical consultants these wells are considered quite unique and we are proud of these technical accomplishments. The ability to achieve production results from these lower geological formations opened opportunities for us to consider other lower layer developments at the Termokarstoye and North-Russkoye fields.

I would now address the question on crude oil forecasts at SeverEnergia. Yes, we erred in our initial assessment of the joint ventures production profile between gas condensate and crude oil. In 2010, we originally assessed a higher level of crude oil production based on our initial geological and geophysical evaluation on fields within the joint venture. As we began drilling wells in the northern section of the license area we encountered gas and gas condensate bearing layers rather than crude oil layers. The downgrade of crude oil production is solely connected to the reclassification of our reserves from crude oil to gas condensate, which, quite frankly, is positive because of better field economics.

If we look at the present situation from this perspective we were able to derive higher economic value for our shareholders than by solely producing crude oil. Creating shareholder value is our primary focus. We maximized value creation under this scenario by getting multiple streams of revenues from each wellbore – natural gas for sale, refined petroleum products for 100% export as well as receiving additional margins from the processing of the unstable gas condensate at the Purovsky plant and a higher combined basket price for our refined products sold internationally. I have been somewhat surprised by this focus on us not reaching the initial estimates of crude oil production when in fact we have significantly exceeded our initial forecasts of gas condensate production and achieved better project economics.

We are currently developing plans to bring additional Arcticgas fields' on-stream such as the East-Urengoyskoye and the North Estinskoye fields but plateau production from these new fields will only be reached after the end of this decade. In addition, we have plans to begin the next stage of Achimov development at the Urengoskoye field as well as targeting the Valanginian layers at the Samburgskoye field. Mr. Mikhelson recently stated at the Vladivostok Economic Forum that we plan to begin first phase of crude oil production of 1.1 to 1.2 million tons at the Yaro-Yakhinskoye field around late 2018, early 2019. We will continue to assess the crude oil potential at this joint venture but, as of today, I believe we have designed a development program that efficiently exploits the joint venture's resource base.

We have begun producing and marketing associated petroleum gas (APG) from the Yarudeyskoye crude oil field in the 4Q 2016. This information has not been previously announced to the market so here is a little upside surprise to your forecasts. We are producing about 9.8 thousand tons of crude oil per day, or 3.5 million tons annually, and will begin producing about 3.5 to 3.8 mcm per day of APG, or the equivalent of about 1.0 to 1.1 bcm per annum. With this output, we expect to add 500 to 600 million cubic meters of gas to our production profile in 2016. Our geologists are assessing the field's potential gas resources so it's premature to make any further comments at this point, but either way this is positive for us.

I would now like to spend a few minutes to talk about our exploration activities at various fields.

At the North-Russkiy license area we completed the testing of well #305 and discovered the Kharbeyskoye gas condensate and crude oil field with preliminary reserve estimates of 45 bcm of natural gas, four (4) million tons of gas condensate and seven (7) million tons of crude oil under Russian reserve classification C1 + C2. We are currently planning further exploration work for the remainder of 2016 and 2017, which may yield additional hydrocarbon reserves on this newly discovered field.

Well #305 confirmed commercial condensate production at the Jurassic deposits with a high condensate concentration factor in the natural gas stream of 270 grams per mcm. The Kharbeyskoye field is already the third field discovered on the North-Russkiy license area, with earlier discoveries at the North-Russkoye and Dorogovskoye fields. Combined with the East-Tazovsky license area acquired in 2013, the North-Russkiy cluster should contribute meaningful production growth post 2020 when these fields are expected to reach their respective plateau production profiles. Production from the North-Russkoye field is expected commence towards the end of this decade.

A new gas condensate deposit – BU12 – was discovered on Arcticgas' Yevo-Yakhinskoye field with the successful testing of exploration well #83. Gas condensate flowed from the both the Achimov and Valaginian layers with a high

condensate concentration level of up to 400 grams per mcm. This new exploration discovery increases the field's asset value and will definitely have a positive impact on the impending decision to start the field's development activities.

We completed the running and processing of three-dimensional (3D) seismic surveys at the North Obskiy and Nyakhartinskiy license areas with both areas yielding positive initial results. We will provide more information later on our development plans for the Nyakhartinskiy license area as this field is in close proximity to our Yukharovskoye field and would benefit from joint development synergies. It is too early to discuss potential development at the North-Obskiy license area.

In September, we announced the acquisition of the Syadorskiy license area on the Yamal peninsula via a tender auction for a one-time payment of RR 404 million. The geological, exploration and production license has a term of 25 years and expands our resource position in the northern part of the Yamal peninsula. As of 1 January 2016, the license are held approximately 25 bcm of C1 natural gas reserves and recoverable resources totally 63 bcm of natural gas and 18.6 million tons of liquid hydrocarbons.

We also recently announced that together with Italian oil and gas company Eni we signed a concession contract with the government of Montenegro for the exploration and production rights on four (4) offshore blocks in Montenegro. The concession agreement covers offshore blocks 4, 5, 9 and 10 in section 4118, comprising a total area of approximately 1.2 thousand square kilometers located in the territorial waters of Montenegro. Eni was appointed the operator of the concession and has extensive exploration and production experience in the Adriatic Sea. We will each hold a 50% share in the concession agreement.

The concession agreement envisages a mandatory work program comprising the running and processing of 3D seismic, and the drilling of two (2) exploration wells targeting specific geological zones over the exploration phase period of seven (7) years.

When you combine the diverse exploration and development activities that we are currently working on with the present construction activities at the Yamal LNG project, you can easily understand why we believe NOVATEK is not ex-growth, but instead at the very beginning of the next growth phase for the company. I would also like to point out that my discussions this evening on exploration and development activities did not even address the huge upside that our Gydan peninsula fields offers us in terms of future production growth as well as LNG projects.

Our production profile for 2016 and 2017 will remain relatively flat or slightly decline for natural gas at our core fields until we bring on-stream the first LNG train at Yamal LNG and the new production mainly from the North-Russkoye cluster and

possibly lower producing formations like the Jurassic. As Mr. Mikhelson stated in his recent interview with Kommersant as well as what I have reiterated this evening, we are not too concerned by these developments as we have the substantial hydrocarbon resources to maintain our overall production plateau. It's essentially a matter of priority in developing our asset portfolio rather than a lack of opportunities.

As you know, the third quarter is generally a transitional seasonal period in terms of natural gas sales as we finalize inventory build-ups heading into the traditional winter periods comprising the fourth and first quarters. Therefore, our results tend to fluctuate in this period based on various seasonal factors but overall, we are reasonably pleased with both our operational and financial results.

We drilled 53 production wells in the first nine months of 2016 versus 77 wells drilled in corresponding 2015 period. Our reduced drilling reflects the maturity of our present development plans and corresponds with our move towards more maintenance drilling as reflective in our capital spent throughout the current period and the first nine months of 2016. Our reduced drilling activities and capital spent by no means represent our inability to grow our operations as I already outlined, but rather a period to focus on launching Yamal LNG and preparing for the next phase of production growth.

We spent approximately RR 7.7 billion in capital expenditures during the third quarter 2016 on a cash basis, with approximately 41% of the funds spent on crude oil developments at the Yarudeyskoye and East Tarkosalinskoye fields, as well as some preliminary capital spent on exploratory drilling at the West Yurkharovskoye field amongst other activities. Our capital expenditures on a cash basis declined by roughly 37% year-on-year (y/y) but slightly increased by 6% quarter-on-quarter (q/q). The absolute reduction in capital spent demonstrates the lower capital intensity inherent in our existing capital program and our move towards maintenance capital in our current investment cycle. For the nine months ended 30 September, we spent approximately RR 24 billion on a cash basis towards our 2016 capital program. We originally guided capital spending of approximately RR35 billion for the full year 2016, but it does not look like we will spend this complete amount in the fourth quarter due to some changes in our decision to make prepayments to contractors. We remain committed to this overall guidance as part of our capital plans but will more likely shift some of the amounts spent in the 2017 capital program. As of today, it appears that our 2017 capital program will further decline to about R 28 billion to RR 30 billion, but I will reconfirm this amount later in the year once budgets are formally approved.

Total oil and gas revenues in the third quarter (Q3) 2016 was RR 126 billion, representing an increase of 8% y/y and consistent with the revenues we achieved in the second quarter. As we had experienced throughout 2016, our oil and gas revenues fluctuate period-on-period largely driven by increases in our liquids revenues, volatility in benchmark commodity prices and the corresponding

translation of these foreign earnings into Russian roubles. Volume growth in crude oil sales was the main factor contributing to our increased revenues as we realized mixed commodity prices for our liquids products y/y and q/q consistent with the movements in the underlying benchmark reference prices. The most notable change q/q was the strengthening LPG price on the Russian domestic market, but we generally realized lower prices across our product range as well as lower realized netback prices for natural gas during both reporting periods. This reflects a supply/demand imbalance in the marketplace for products sold internationally but also takes into consideration the seasonality impact on domestic gas sales as well as increasing volumes sold on the commodity exchanges and some impact from geographical shifts in sales.

Our liquid revenues now account for over 50% of our total revenue and we expect this trend to continue for the foreseeable period, accounting for approximately 59% of our total revenues in the third quarter. This trend is positive as increased foreign earnings better match our predominately US dollar-denominated debt portfolio as well as positively impacting our revenues in the reporting periods due to the favorable movements in the USD/RR exchange rates.

Our volumes of natural gas sold increased as compared to the respective reporting periods. We increased our gas sales volumes by 1.3% y/y and 2.8% q/q, but we also injected natural gas into the underground storage facilities reflecting seasonal consumption patterns on the domestic market. We continue to optimize our domestic gas trading operations by utilizing the St. Petersburg Commodity Exchange, purchases from third parties and the injection/withdrawal of gas from storage to meet our end-customer demand requirements. We sold 93% of gas volumes to end-customers and 7% to wholesale-traders.

For the nine months period, we sold a total of 46.3 bcm of natural gas versus 44.8 bcm in the corresponding period of 2015, of which we sold slightly more than three (3) billion cubic meters (bcm) on the commodity exchange, representing a more than tenfold increase in exchange sales over the prior year. We sold 14.6 bcm of natural gas in the third quarter 2016 achieving consistent volumes sold within the low seasonal periods.

Throughout 2016, we rebalanced and tweaked our gas sales portfolio with some shifts in regional sales to reflect changes in our customer base as well as increased volumes sold on the St. Petersburg Mercantile Exchange. With these changes, our average natural gas prices decreased by about 4.4% y/y and by less than one-percent q/q. The decrease in our average realized prices led to declining average netbacks for end-customers y/y and q/q as we sold more volumes closer to our production facilities and realized weaker seasonal pricing on the exchange related trades, which was somewhat mitigated by lower transport and storage costs. For the nine months ended period, we increased our end-customer average netbacks by 4.4% or RR 96 per mcm over the corresponding 2015 period. More importantly,

we have already achieved higher commodity traded prices exceeding the regulated FTS price for our recent trades as we enter the winter period.

We sold 4.2 million tons of liquids representing a 21% increase over the volumes sold in the prior year and slightly higher than the second quarter by 1.1%. The average prices we received in dollar terms were generally mixed across our complete product range because of continued volatility in the international benchmark reference prices. This effect is somewhat offset either positively or negatively by movements in foreign currency exchange rates as well as the corresponding changes in liquids export duties.

There was a lot of variability in our liquids sales in the third quarter due to seasonal changes, commodity prices, export duties and geographical mix. Since we sell our liquid prices at spot prices, we try to maximum our revenues and netbacks based on our assessment of market conditions in different geographic zones. Overall, during the third quarter, we increased our net liquid sales by 711 thousand tons, largely driven by crude oil production from the Yarudeyskoye and East Tarkosalinskoye fields by 906 thousand tons, which were partially offset by declining gas condensate sales of 258 thousand tons to export markets and increasing sales of LPG and other refined products as compared to 2015.

We had declines in our naphtha sales over the comparative reporting periods due largely to volume movements, price changes and increases in export duties. We shifted both gas condensate and naphtha sales more towards the European and US markets this quarter as fewer volumes were sold to the Asian Pacific region, which meant lower realized prices but also lower transport costs. The combined effect of these changes for stable gas condensate and refined product sales resulted in a higher weighted average netback as compared to the prior year by 7.5%, but lower against our second quarter by 8.2%, driven largely by lower commodity prices. We also realized seasonal strong domestic LPG prices between the second and third quarters 2016 although the volumes sold this quarter were slightly lower.

There were no major surprises to our operating expenses in the third quarter. Our operating expenses were in-line to the growth in our business, representing an increase of roughly 10% y/y and 4% q/q. Purchases represented the largest cost category this quarter and accounted for 26% of our total operating cost as a percentage of revenues, again exceeding that of our transportation expenses. Our natural gas transport cost were reduced by 5% y/y due to the change in our average tariff rate per mcm, which was slightly offset by an increase in volumes sold. General and administration expenses increased mainly for the same historical reasons – indexation of salaries effective the 1 July, increased hiring due to expansion of operations, accrual of bonus payments and social benefits. On a y/y basis, G&A expenses increased by 30% but represented only 3% of our total cost relative to revenues. Overall, we increased our total headcount by 301 individuals to 7,188 employees across the NOVATEK Group.

Our depreciation, depletion and amortization, or DDA, expenses increased y/y and q/q representing the largest percent change relative to revenues. The increase is mainly attributable to crude oil production at both the East Tarkosalinskoye and Yarudeyskoye fields during the reporting periods, as the unit rate charged is higher for crude oil than natural gas. Our total operating expenses are also impacted by movements in "Change in Inventory" between reporting periods due to fluctuations in our inventory balances over the course of the year.

Our balance sheet and liquidity position strengthened in the third quarter 2016 and the nine months period, which was obviously supported by the receipt of funds from the Silk Road Fund on the sale of the 9.9% equity stake in Yamal LNG in the first quarter as well as generating strong operating cash flows, reduced capital intensity and the repayment of both short- and long-term debt.

I would like to highlight to our fixed income investors and credit rating analysts that all of our liquidity and credit rating metrics improved throughout the nine months ended 30th September, and we reduced our net debt from RR 330 billion to RR 200 billion, or by 39%. I raise this specific point because periodically we field questions concerning our ability to service our short-term debt as they mature, so I wanted to make it absolutely clear that we generate sufficient operating cash flow to service our debt as they become due, settle our liabilities, internally fund our capital program and pay dividends to our shareholders.

Free cash flows were strong in the 3Q 2016. We generated RR 35 billion of free cash flow during the quarter and this amount was one of the highest levels achieved in a traditional weak seasonal period. Free cash flow generation remains strong in 2016 although there are seasonal fluctuations and some one-off adjustments, and I believe it will remain strong for the next several quarters.

CONCLUSION

In summary, we achieved another solid set of seasonally adjusted financial and operational results in the third quarter 2016, and we are positioned to enter the upcoming peak winter season and conclude the year in a strong manner. We have consistently outperformed our peer groups over the past several quarters despite volatile commodity prices and a relatively weak macro-environment. In this past quarter, we sustained our revenues and margins and generated very high free cash flow despite quarter-on-quarter decreases in oil and oil product prices and no escalation in the domestic gas tariff as was originally forecasted.

I also want to unequivocally state that we understand your concerns about the declines in our core production profiles and, hopefully, I have addressed some of these points in my update tonight. Each and every one of you this evening should be ensured that we are appropriately addressing this operational question. We have a sizeable asset base at various stages of exploration and development and we are beginning to target projects for future production growth and cash flow

generation. There are many exciting projects ahead for us within our existing opportunity set and some that I am unable to talk about tonight as we are currently in negotiations. So, I am confident that you will eventually draw the same conclusions that we are not ex-growth.

Our primary focus over the past couple of years was to successfully launch the liquid projects at our joint ventures and make to significant progress in bringing forth our flagship Yamal LNG project, and this meant making some conscientious decisions on delaying capital spent on certain exploration and development activities. Now that we have concluded the external financing package for the Yamal LNG project and have finalized our commitments to finance this project we can refocus our efforts on new opportunities as they materialize as funds have been unlocked.

I was hoping to provide you this evening with a date for our strategy day but we are currently evaluating a few opportunities that have not been finalized as of tonight's conference call which will ultimately impact our investment decisions and forthcoming strategy. We believe it is prudent to finalize this process first, discuss these opportunities with our partners, and then incorporate them into our strategic update. We have historically provided the investment community with a relatively concrete roadmap to achieve our strategic growth objectives. Our goal is continue this track record.

I want to strongly stress that we are not ex-growth as some would like to portray us today but rather at a new infliction point in our future strategic development with positive dynamics. We have delivered exceptional production growth considering our size and scale of operations, and this growth was delivered at some of the lowest cost metrics in the global oil and gas industry. We did not leverage up our balance sheet with debt-driven production growth as many of our peers, but rather stayed within our core competencies of capital discipline, cost control and project execution.

We are now a year away from launching the first LNG train at Yamal LNG and enormous efforts has been expended to get to this stage of the project, and the closing of the main external financing package unlocks funds to be spent on other development activities. We plan to commission and start the first LNG train during the first half of 2017 and the scheduled delivery of the first LNG cargo in the second half of 2017 is still valid. Our goal is to become a major player in the global gas markets, and 2017 begins our journey.

I would like to thank everyone for attending tonight's conference call and now open up tonight's session to question and answers.

Thank you.