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# The Boris Field Development – Short Cycle Time and High Well Productivity

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## Abstract
BHP Billiton has completed the development of the Boris field, located in Green Canyon block 282. The two development projects were executed with short cycle times, and the wells have very high productivity. This paper reviews both projects, including subsurface issues, well completions, project execution, production issues, and lessons learned.

## Introduction
The Boris field is located in Green Canyon block 282, approximately 170 miles SSW of New Orleans, and approximately five miles southeast of the Typhoon field located in Green Canyon 236/237. The Boris field is operated by BHP Billiton with a 50% interest. Other partners include ChevronTexaco and Noble Energy, Inc., each with a 25% interest. The Boris field was developed as a two-well subsea tieback to the Typhoon production facility. Typhoon is owned by ChevronTexaco and BHP Billiton, each with a 50% interest, and operated by ChevronTexaco.

Production from the 282 #1 well in the Boris south reservoir began on February 3, 2003. The 282 #2 well in the Boris north reservoir had first oil seven months later on September 17, 2003. The finding and development cost of the Boris field, including drilling of both exploration wells, totaled about $140 million. The project has produced approximately 4.3 MMBO and 6.5 BCF of gas as of December 31, 2003. This project was an important milestone for BHP Billiton because it was the first operated deepwater project for the company, and it was brought onstream safely, quickly, and efficiently.

## Boris South – Exploration (GC 282 #1)
The first Boris exploration well was driven by the Typhoon near-field strategy of low-risk, high-margin reserves with short cycle times that utilize existing infrastructure. The 282 #1 well was spud in August 2001, only one month after the Typhoon facility began production. The exploration plan called for an initial penetration of the seismic amplitude followed by a short sidetrack to a production location. The sea-floor location of the well was chosen with development in mind. A sea-floor escarpment exists between the amplitude location and the Typhoon facility that would have been risky to cross with a flowline. A surface location west of the amplitude was chosen to mitigate this risk. This caused a long-reach deviated well trajectory with slightly higher risk and expense.

After a successful initial penetration, the updip sidetrack experienced mechanical problems, requiring a bypass. The bypass reached the drilling objective but pressure data indicated that it was in a lower pressure regime than the original penetration, which was interpreted as possible compartmentalization. It was later demonstrated that the decreased reservoir pressure was caused by hydraulic communication with production from the Typhoon 237 #2 well producing from a reservoir that shares a common aquifer with the Boris reservoirs.

A fourth penetration was drilled and finished in November 2001. The final location was chosen to optimize value, balancing increased recovery in a high structural position against sands that thin updip, therby decreasing flow rate.

There was a desire to drill the deeper B6 horizon, but there was a risk of hitting pressure in the onlap surface just below well TD. However, drilling deeper was required to allow for the eventual gravel-pack completion that would be installed. Careful drilling provided just enough room for the completion.

## Boris South – Subsurface
There are two seismic amplitude anomalies located along the eastern rim of the Typhoon mini-basin. These amplitudes correlate to the main pay horizon in the Typhoon field. The 282 #1 well tested and appraised the southern amplitude, discovering oil-bearing, high-quality turbidite sands. The Boris rock and fluid properties have been characterized, and are very similar to the properties of the Typhoon main pay B4 sand in the GC 237 #2 well.

The reservoir depth is about 13,600 feet TVDSS. The reservoir is filled with undersaturated oil and supported by an aquifer that is prevalent in the entire eastern portion of the mini-basin. Preserved downhole samples of the oil show a 33.5 degree API gravity with a 1,550 scf/bbl GOR. Oil viscosity is 0.6 cp. It is considered a sour crude, and contains asphaltenes with similar properties to those found in Typhoon, which are being produced without incident at this time.

## Boris South - Development

Development work for the Boris South project began as soon as the exploration well found hydrocarbons. The subsea tieback scenario was proposed, and a detailed facility peer review was held in December 2001, leading to a long-lead AFE that was approved in January 2002 and project sanction shortly thereafter.

The strategy envisioned at the time of Boris South sanction was to leverage the Typhoon operation with the goal of reducing project costs and cycle time, which included:

- keeping the Typhoon infrastructure full by utilizing spare capacity to process produced fluids at minimal cost,
- utilizing the Typhoon export system and marketing arrangements to maximize the value of production,
- improving on well productivity with lessons learned from Typhoon well completions,
- synchronizing completion operations with Typhoon's well work program to reduce rig costs,
- utilizing existing spare equipment to expedite schedule,
- utilizing BHPB personnel and members of the Typhoon project team who were familiar with the facilities, and
- designing Boris South facilities so that other production could be tied-in at low cost.

To achieve these goals, a multi-well subsea manifold with a single flowline and umbilical was selected as the development concept for the Boris field. Figure 1 illustrates the subsea architecture for the Boris Development Project. This configuration reduced the cost of subsea equipment yet gave flexibility to tie-in additional wells at minimal cost, which was important because of the presence of the northern amplitude.

The development plan included the following:

- complete the 282 #1ST3 well,
- install a single, 6-mile, externally-insulated flexible production flowline,
- install a three-well subsea manifold with a fourth hub for a contingent subsea pig launcher or a second production flowline,
- install a 6-mile electro-hydraulic control umbilical with an associated subsea distribution unit for distribution of hydraulics, chemicals and power/comms for up to three production wells, and
- modify the Typhoon topsides facilities to incorporate production from the Boris field.

Two of the three slots on the subsea manifold were designated for the Boris-1 and Boris-2 wells. A third slot is available if needed in the future. The flowline is 4.5 inch ID, five-inch nominal diameter and has capacity of about 20,000 BOPD. Existing pull tubes on the TLP were used to connect the catenary riser and umbilical. Typhoon topsides modifications included expansion of the surface production inlet manifolds to maximum with two additional inlets. A waste heat recovery unit was installed to augment existing production needs, as well as provide for the additional heat loads expected with the Boris production. A chemical injection skid and subsea controls were also added.

**Development Risk Assessment.** Several risk issues were identified as part of the project decision process. The risk of the completion cost exceeding budget was identified, including the running of the gravel pack, weather delay, and higher than budgeted rig day-rate. It was felt that the lessons learned from the Typhoon well completions would help to mitigate this risk. The original project schedule called for the completion to occur in the August-October period, avoiding the stormy winter weather. Actual schedule encroached into the period of poor weather and caused additional cost and schedule delay.

Reserve uncertainty was also identified as an area of risk. Potential for non-amplitude volume provided upside, while possible connectivity issues and uncertainty in the level of the oil-water contact caused concern.

Schedule uncertainty was evaluated and deemed not to be a significant risk because the well had already been drilled, the long lead items had already been ordered, and completion rigs were readily available.

**Capital Description.** The actual gross capital expenditure for the Boris South project was $91 million, which includes $32 million in exploration costs.

Gross sanction forward cost estimate for this project was $48 million compared to an actual cost of $59 million. The well completion was about one-third of this cost. Principal reasons for the difference between sanction and actual spend are as follows ($ million):

$7.2 Incremental rig costs associated with weather, equipment downtime, and non-productive time delays
$4.0 Incremental installation costs associated with weather downtime and extra work outside the scope of the original estimate
$2.9 Incremental project team costs due to project delays and third party engineering costs

The above costs were partially offset by savings in various other project areas resulting in the final project costs detailed above. The reasons for the incremental costs are discussed in the next section.

**Schedule.** The original project schedule called for first production in December 2002. Production actually commenced on February 3, 2003. Table 1 summarizes sanction versus actual key project execution milestones.

Significant delays were associated with the well completion. The actual completion duration was 97 days versus the planned duration of 50 days. 23 days of delay was caused by weather downtime due to tropical storm Hanna, hurricanes

Isidore and Lili, and heavy seas. Additional delay was experience due to non-productive rig time and slower execution time.

Table 1
Sanction vs. Actual Milestone Dates

| Milestone | Sanction | Actual |
|---|---|---|
| Long Lead Equipment Orders | 02/02 | 02/02 |
| Award Rig Contract | 05/02 | 05/02 |
| Tree Delivery | 07/02 | 07/02 |
| Controls Delivery | 07/02 | 07/02 |
| SIT Start | 07/02 | 08/02 |
| Completion Start | 08/02 | 08/02 |
| First Oil | 11/02 | 2/03 |

There were also delays associated with the flowline and umbilical installation. The actual installation required 56 days due to significant delays associated with weather downtime (22 days) and non-productive time (15 days). Overall, the total delay in project execution was 84 days. Some contingency for schedule delay was included in the project schedule, but the first oil date was still 34 days late. Figure 2 illustrates the actual Level 1 project schedule.

**Cycle Time Reduction.** Part of the Boris strategy involved reduced cycle time to add value. This was balanced by not taking unnecessary risk. To accomplish this, several groups needed to be aligned. Internally, it was important to align objectives between the Exploration and the Development organizations. This involved the realization that the exploration well would be the production wellbore, requiring a hole size large enough to accommodate a gravel pack completion. Sea-floor location had to provide for a safe flowline route. The data gathering requirements around logging, fluid sampling, and pressure data were also agreed. Within the partnership, the three companies needed to be aligned. This involved frequent communication and the willingness to resolve issues quickly for the good of the project. The well bottom-hole locations, production-handling agreement, and issues around modification of the Typhoon facility had to be agreed. This was aided by the cooperation of ChevronTexaco as operator of Typhoon, and by BHP Billiton and ChevronTexaco having working interest in both Typhoon and Boris. Alignment with suppliers was critical and involved the use of standardized equipment, the development of strategic sourcing and framework agreements, and win-win attitude.

In an effort to expedite the schedule and reduce cost, the project team elected to use surplus subsea equipment from ChevronTexaco's Gemini Project. Only slight modifications were necessary to configure the equipment to meet Boris' requirements. Some new components including a completion guide-base and subsea manifold were required. Running tools and spares were sourced from the Gemini suite at reduced cost.

**Principal Suppliers.** The following suppliers were used in the Boris projects:

| | |
|---|---|
| Drilling Rigs | Dimaond Ocean Quest<br>Diamond Ocean America |
| Completion Rigs | Transocean Falcon 100<br>GlobalSantaFe Arctic 1 |
| Completion Services | Schlumberger (Frac/Perf/SCSSV)<br>Halliburton (Slickline/Well Testing)<br>Expro (SSTT/Downhole Gauges)<br>Weatherford (Tubing/Fishing/Makeup)<br>Baroid (Fluids) |
| Tree Modifications | Cameron |
| Manifold | Cameron |
| Subsea Controls | ABB |
| Umbilical | Oceaneering |
| Flying Leads | Deep Down |
| Flowline (Hard Pipe) | US Steel |
| Flowline Coating | Bredero Price |
| Flowline (Flexible) | NKT |
| Installation Services | Boris 1 - Global<br>Boris 2 - Oceaneering<br>Topsides - Dynamic, Test |

**Health, Safety, and Environmental.** The Boris Project HSE Plan included contractor safety integration into the overall plan. For rig activities, bridging documents were created between the Boris Project HSE Plan and the Rig HSE Plan to cover project execution. A specific Boris HSE plan was prepared and submitted to both the Minerals Management Service and to the US Coastguard for their approval as required by the regulations.

A project Hazard Identification (HAZID) Review showed that the overall risk profile of the proposed development plan was acceptable and no hazards were identified which posed unacceptable risks. Follow-up HAZOP's and PHA's were performed at scheduled intervals to ensure a safe, manageable and operable project. The Boris South project was executed with no lost-time incidents.

**Typhoon Facility.** The Typhoon field was commissioned in July 2001 and is producing oil and gas from Green Canyon blocks 237 and 236. The field was developed with four subsea wells tied back to a Seastar® mini-tension leg platform (TLP) in about 2100 feet of water. After separation, oil is exported via a 10" pipeline to the Boxer platform in Green Canyon 19 while gas is sent through an 18" pipeline to Eugene Island Block 371. Typhoon began production in July 2001.

The process system on the TLP is designed for 40,000 STB/day of oil, 60 million scf/day of gas and 15,000 bbl/day of water production. Peak throughput of the facility has been measured at 42,000 STB/day.

## Boris South – Production

The 282 #1 well started production from the Boris South reservoir on February 3, 2003. This was only fifteen months after the field was discovered. The well produced oil at rates as high as 18,000 STB/day, limited by the Typhoon ullage. The reservoir permeability to oil has been defined by multiple build up analyses as 1,100 md.

**Operating Costs.** Operating costs at Boris are derived from costs incurred for production handling at the Typhoon facility pursuant to a Production Handling Agreement between the Typhoon owners and the Boris owners as well as field-specific costs for the subsea potion of the system (periodic inspections, well interventions, etc.).

**Sustained Casing Pressure Remediation.** Shortly after production began from the 282 #1 well, it became apparent that there was unusual casing pressure. This was despite a successful casing integrity test performed during the well completion to verify the integrity of the system. Diagnostic work indicated that the leak was probably in the chemical injection valve located 2495 ft below the mudline, just above the SCSSV. The leak was intermittent and at times was temporarily stopped by injecting a clear mineral oil. The leak reappeared several times during shut-in / start-up cycles of the well.

Following rigorous evaluation, the MMS granted a temporary departure to operate the well within stringent, specified casing pressure ranges. However, the limits that this imposed on production operations required that remediation be attempted. A rig-based intervention was deemed cost prohibitive, so alternate means of eliminating the leak were explored.

Two options for pumping sealant to the downhole leak site were considered: using an ROV to pump through the subsea tree, and pumping through the umbilical from the platform. After performing a peer review and HAZOP, the project team concluded that the platform option was the preferred method. This option permitted a larger inventory of sealant to be injected which allows for multiple pumping operations if required. It was also less costly. A mock-up test was performed to model the restrictions in the flow path. It was assumed that the CIN1 chemical injection line used for the operation would be lost, but this was acceptable as mixed chemicals could be applied through other umbilical lines if required.

Sealant volume of 32 gallons was pumped through the umbilical on October 21, 2003. The sealant was spotted in place. Then, mindful of hydrate formation envelopes, pressures were manipulated to induce the leak. This bleed off process created a differential pressure of approximately 5000 psi across the leaking chemical injection mandrel to the annulus. The leak was observed and verified by rising casing pressure. Approximately 5 gallons of sealant was displaced across the suspect chemical injection mandrel, resulting in annulus pressure leveling out and then slowly decreasing (normal annulus cooling). The well was left shut-in and the annulus pressure was monitored for over twelve hours during the cool down process, which also allowed the sealant to cure. The chemical injection isolation valve at the subsea tree was closed to insure the sealant remained spotted at the mandrel. The job was an apparent success, and normal production operations followed.

The casing pressure was monitored continually, and the leak re-appeared (at a smaller apparent rate) on November 15, 2003. Sealant that remained in the line from the initial application was pumped and was successful in sealing the leak. There are still about 25 gallons of sealant remaining in the line to preform future re-injections as required.

The CIN1 umbilical line and associated plumbing near the injection site has been plugged and the entire CIN1 system has been “locked-out” and “tagged-out” both physically and electronically. The sealant manifold and valving including the flowmeter are now mounted on the chemical injection skid to allow for future injections if necessary.

## Boris North - Exploration – Green Canyon 282 #2

There was some debate among the partners about waiting to drill Boris #2 until after first production from Boris #1 to mitigate risk, but in the end it was agreed to progress on an accelerated schedule. In retrospect, this was a good decision because the well was a success and Typhoon ullage was available. There was also debate concerning the proposed bottom-hole location of the well, as BHPB and ChevronTexaco had different seismic data with differing interpretations. A compromise location was reached and the well was approved.

The Boris #2 well was spud in June 2002 and reached total depth in August. The uncertainty in seismic amplitude location resulted in a penetration with only minimal reservoir sand at the estimated top of structure. A decision to sidetrack downdip into a more complete section of the reservoir, as indicated by the re-calibrated seismic thickness estimates, resulted in the thickest oil-sand accumulation of any penetration in the mini-basin.

## Boris North – Development

Shortly after the drilling of Boris #2 ended, a long-lead AFE for the Boris North project was approved. The integrated development AFE was approved in January 2003, just as Boris South first oil was approaching. The development concept was a single-well tie-in to the existing Boris South subsea manifold. An existing spare tree owned by the BHPB-operated Keith field partners in the UK was selected over a new-build. To expedite schedule, the tree was flown to Houston on an Antonov plane. Tree modifications were executed in Cameron’s Berwick facility. Utilization of the Keith surplus tree was more cost-effective for the Boris partnership than newbuild alternatives, even considering the expedited transportation.

A few weeks of project delay were experienced waiting for the contracted completion rig to become available. Upon arrival, the rig performance was excellent. The completion was executed with only ten percent non-productive time excluding weather.

The actual gross capital expenditure for the Boris North project was $49 million, compared to an AFE cost of $53 million. This included the exploration well cost of just over $20 million and the well completion cost of about $15 million.

The cost savings was primarily associated with a lower rig rate and efficient operations for the well completion.

### Boris North – Production

First production from Boris North occurred on September 17, 2003, only thirteen months after the field was discovered. Production has been flowing without any issues.

### High Productivity Well – Completion Design and Implementation

The Boris gravel packs were designed to give minimal skin and pressure drawdown. The well productivity index of each well is over 20 BOPD/psi. The #1 well has flowed at rates approaching 18,000 BOPD with less than 300 psi draw-down on the fracpack.

The planning and execution of the completion program was a significant aspect of achieving high well productivity. Pre-planning, detailed procedures, experience level of supervisors, contractor selection, and job management contributed significantly to the result.

The initial pressure transient analysis yielded completion skin factors of 5.7 and 9.8 for Boris #1 and #2, respectively. However, the wells cleaned up over time, and analysis of pressure build-up data from multiple shut-in events resulted in final skin factor values of 3.5 for Boris #1 and 0.8 for Boris #2.

The productivity of both Boris wells exceeded expectations because average permeability was greater than expected. Also, for the #2 well, net pay thickness exceeded pre-drill estimates because the sidetrack location was placed in a thicker section of the reservoir than originally prognosed for the initial wellbore. For both wells, skin factor values were lower than expected considering that higher permeability completions usually yield higher skins as indicated by available industry $kh/\mu$ data for sand control completions.

**Completion Procedure Issues.** The completion procedure focus in the detailed design effort involved both productivity and completion longevity concerns. Those key areas of concern were:

1) Asphaltenic crude with high asphaltene flocculation pressures and significant emulsifying tendencies
2) Difficulty in obtaining a screenout during fracpacking in an analog near-field frac pack completion
3) Fines migration over time, and the presence of zeolitic clinoptilolite clays which react negatively with some acids
4) Perforating/surge approach coupled with the estimated $kh/\mu$ with respect to the overall impact on final completion skins; skin results were also a significant consideration in evaluating the value of surging as was the relationship of surge risk versus reward.
5) Post-surge fluid loss control including pill spotting versus losses “healing” approach as well as removal of pills prior to gravel placement. A related consideration was the potential benefit of tubing bailer cleanout of perfs in lieu of reverse circulation cleanout procedures.
6) Post-pack fluid loss control
7) Proppant size optimization with no whole core in either well and only sidewall core in the first well.
8) Post-perf sandface stabilization after acid stimulation prior to placement of gravel
9) Payzone cement isolation and containment of frac pack
10) Compaction-related stresses during depletion (should water drive be limited) and mitigation of damage from same
11) Assurance that toolstring “train-wreck” risk was minimized

**Completion Procedure.** The following steps were taken to address the above issues:

1) a) Extensive non-emulsifier testing was done to optimize the high-density brine recipe. Compatibility testing was performed for all treatment fluids with appropriate modification of recipes. Previous lab studies of similar crudes had yielded valuable results that had been successfully implemented. Boris testing followed in those footsteps to arrive at similar results, although the additional stimulation fluids used at Boris required supplemental testing.
   b) Further testing involved the evaluation of any tendency for asphaltene deposition on tubulars. This followed the effort that had been undertaken in a completion study where implementation of phenolic resin tubular coating successfully mitigated the risk of asphaltene deposition in the flowstream below chemical injection valves. A similar laboratory result was seen with Boris crude, so the same coating was installed in Boris tubulars. Due to the relatively low cost, the coating was run above the chemical injection valves as well, allowing for additional asphaltene insurance.

2) Both frac designs implemented had a more aggressive schedule to ensure a screenout was obtained. Contingency plans involving a rate slow-down were also in place including taking returns in the last stage in order to ensure annular pack integrity, which was especially important in the second well due to it’s long interval. Additionally, an “equilibrium” injectivity treatment was originally planned in order to obtain a more accurate closure pressure. However, operational difficulties arising from inaccurate estimates of permeability required some data frac adjustments that prevented this step from being implemented in both completions.

3) Increasing skin factors in analogue wells were possibly caused by migrating fines, possibly after compaction pore-throat failure. Therefore, consideration was given to a deep penetrating clay acid treatment, which was viewed to have other benefits such as improving frac fluid cleanup and aiding in perforation preparation prior to fracpacking. The presence of clinoptilolite clays complicated this effort due to their damaging reaction with HCl acid. The final recipe, nevertheless, maintained an aggressive clay attack approach while minimizing HCl

content by using organic acid in concert with HF. The thick interval in the second well required that acid diversion be implemented in order to treat the entire interval. That was accomplished with a viscoelastic surfactant stage.

4) An informal review was performed regarding both near-field analogs as well as industry gravel pack data on kh/μ versus resultant skin with an effort to analyze the value of underbalance surging. It was concluded that the incremental cost to surge was justified based on skin reduction in moderate to higher kh/μ completions. However, it was felt that the risk of TCP gun sticking could be reduced by surging after perforating with the tools raised above the perf interval. This also allowed for a more aggressive underbalance surge pressure to better clean the near-perforation area. Incorporation of an air gap allowing for a small volume of flow yet a high level of underbalance was the foundation for this procedure.

5) Tubing bailer tools were chosen as the primary post-perf cleanout approach for these single zone completions because of successful application in other post-perf cleanout wellwork in stack-pack completions. Benefits included elimination of ECD's resulting from conventional reverse out cleanout procedures. Subsequently fluid loss after surging or bailer runs was to be handled via an industry-leading polymer pill design. Removal of the pill prior to gravel placement was to be handled via a breaker acid (with low HCl content) spotted across the perforations with the screen/toolstring in place. Special attention was given to ensuring the acid was placed down to the lower-most perforations by taking a small amount into the washpipe whilst spotting. With minimal losses seen after the bailer runs, there was no need to spot the fluid loss pills. However, the breaker acid was spotted/pumped anyway ahead of the data frac. Actual losses were reduced by allowing the completion to heal with an extended wait period, thus eliminating the need for the pill. It was later estimated that the fine post-perf material in the perforations that assisted in loss reduction was probably more easily removed during the stimulation and fracpack than a pill might have been.

6) Mechanical fluid loss control was reviewed with an eye towards reliability in high-loss scenarios. Although there are significantly advanced and equally expensive fluid loss control valves, the copper beryllium flapper valve appeared to have a solid history of reliability in the desired pressure rating and size. When high post-pack losses were actually experienced it performed as expected, making any potential post-pack fluid loss pill unnecessary. To further mitigate the risk of flapper valve shattering during washpipe removal, the procedure called for a time delay before the washpipe was cleared completely in order to allow losses through the pack to "heal". This was thought to be helpful in reducing any hammer effect that might occur as the flapper closes. Although overall brine losses increased, there was no concern that the additional volumes would be significantly damaging due to the brine testing previously done.

7) Proppant sizing was accomplished in the first completion with careful attention given to the following since whole core was unavailable: 1) sidewall core particle size distribution and 2) the analog completion and it's sidewall core particle size distribution in relation to proppant size actually used. For the first completion this provided some level of confidence in selecting 20/40 proppant in accordance with industry-standard fracpack proppant selection guidelines. However, in the second completion there were no sidewall cores and cuttings analyses proved nearly useless in making the proppant selection. Without the same level of confidence and with a petrophysical estimate that the second completion interval may have a smaller average particle size distribution a smaller 30/50 proppant was selected. It is felt that the larger proppant may have provided a slight gain in productivity had core been available to analyze.

8) Of significant concern after the clay acid stimulation of this very low strength formation was that any swabbing effect might bring in formation material, which could have a significantly negative impact on pack productivity. To reduce this risk no upward tool movement was allowed with the weight-down tool design of choice until after the pack was put away. This forced additional brine volume to be bullheaded into the formation but the laboratory compatibility testing provided confidence that this step would not contribute significantly to an increase in skin damage. Any entry of formation material, on the other hand, could greatly increase skin due to the inability to pack perfs that were covered with formation sand.

9) The first completion did not have a good cement bond a few feet above the top perf. Although this was a concern it was not deemed critical since the cement bond was excellent within the perforation interval. However, a significant net pressure decline occurred (over 1000 psi) during the final stages of the tip screenout just after a significant net pressure gain had occurred. A detailed diagnosis utilizing several pieces of available data indicated that the frac had broken out of zone just above the top of cement allowing bleedoff into the high perm interval just above the payzone, thus stopping further fracture width development. The completion produced only a trace of high chloride water the first few days of flowback so the cement channel had no lasting negative effects other than the frac bleedoff event. In the second well there was a similar lack of cement just above the top perforation with good cement within the pay interval. Elimination of the top three feet of payzone perforations was deemed advisable to reduce the risk of breaking out of zone. Although this slightly increases skin, it was considered a containment mechanism that could prevent the frac from growing very far into the bounding shale and opening the door to another bleedoff into a cement channel connected to an uphole interval. The second fracpack did not experience such a net pressure loss

during the tip screenout. Although it is uncertain that the perforation elimination was effective, fracture growth in some sophisticated models has been known to provide for reduced upward frac growth by inducing leakoff and a commensurate upward tip screenout.

10) The completion intervals were thought to have very high compressibilities. It was estimated from previous experience that significant compaction-related wellbore stresses might increase the risk of well failure in the event that water drive would not keep up with drainage rates effectively resulting in some pressure depletion. To mitigate the risk of wellbore damage/failure the following design steps were taken: (1) heavier weight casing within the payzone (2) crush resistant mesh screens (3) interlocking connections for screens and blank pipe (4) heavier walled base pipe for screens (5) bowspring centralizers and (6) a pinned telescoping joint within the blank pipe to allow for axial movement. Previous work involving finite-element modelling has indicated some potential benefit from the above. It is unknown whether any of these have been effective.

11) Although significant quality control efforts were put into the gravel pack tool preparation an additional mitigation aspect involved selection of field tool supervisory personnel. The service company tool supervisor selection process involved investigation into relative performance of available supervisors with the final choice based on performance information. The performance of that role was deemed critical to job success. Therefore, additional time spent in the selection process was justified. During execution of both fracpacks the actual performance of that tool supervisor proved invaluable.

## Lessons Learned

Short cycle time and high well productivity experienced in the Boris projects present many opportunities for learning. The most significant lessons learned from the Boris projects are highlighted below.

**Project Planning.** As is typical of small reserve, infrastructure-enabled projects such as Boris, cycle time reduction is key to capturing project value. The challenge, generally, is to minimize cycle time while simultaneously ensuring good project planning and efficient execution. While successful in achieving its business objective, Boris did experience its share of challenges due to the pace of execution and a lean staffing model. Key project planning tools such as the Project Execution Plan, the Design Basis Document, and the Project Schedule were developed early in project definition but, due to resource constraints, were not sufficiently updated as the project and organization developed and became more fully defined. As a result, inefficiencies were introduced which may have been avoided had a more aggressive strategy been followed. Key project planning/control documents should be updated often throughout the project execution cycle.

**Contracting/Procurement Strategies & Logistics.** Project pace also presented its share of challenges in the area of contracting and procurement. Factors similar to those mentioned above contributed to a prolonging of the general contracting effort. As a result, several key contract issues continued to be outstanding well into the fabrication phase of the job. This, in turn, led to some commercial challenges as well as technical resource drain during crucial periods of project execution. Appropriate effort (and resourcing) should be applied to the development of full purchase/service contracts early in the project cycle.

**Completion Design.** As discussed above, problems with the downhole chemical injection circuit led to significant operational difficulties during production. Future well completion designs should carefully evaluate the need for downhole chemical injection and consider means of reducing/eliminating if feasible. Further, should downhole chemical injection in fact be required, careful attention should be paid to the design of the downhole circuitry and mandrel to mitigate any leakpath potential.

The high-rate frac-pac and surge completion design used in the Boris wells resulted in low skin factor completions with very high productivity.

**Reduced Cycle Time.** Near-field exploration can effectively create value by reducing cycle time. Using the exploration well for production reduces cost and accelerates the schedule. Planning for the development began as soon as oil was encountered. Long-lead AFE's were used to accelerate procurement on critical-path items in parallel with project justification. Existing trees were modified for use instead of ordering new ones. Boris North was planned during Boris South development, even though the field was yet to be discovered. The Typhoon mini-TLP and export pipelines were designed to accommodate additional tie-back projects. Partner alignment was maintained throughout. All of these factors contributed to a short cycle time.

## Conclusions

1. The Boris Projects were successfully executed and business objectives have been achieved. Significant cycle time reduction was achieved and required the alignment and cooperation of many different groups.
2. The well completion techniques employed on the two Boris wells have generated high-productivity, low-skin completions.
3. The total production from the Boris field is over 20,000 BOPD and 30 MMCFPD and is currently constrained by the capacity of the 6-mile flowline linking the wells to the Typhoon mini-TLP.
4. The application of sealant has repaired a leak in the production system that was generating sustained casing pressure.
5. Total cost of all Boris capital (exploratory and development) was about $140 million.

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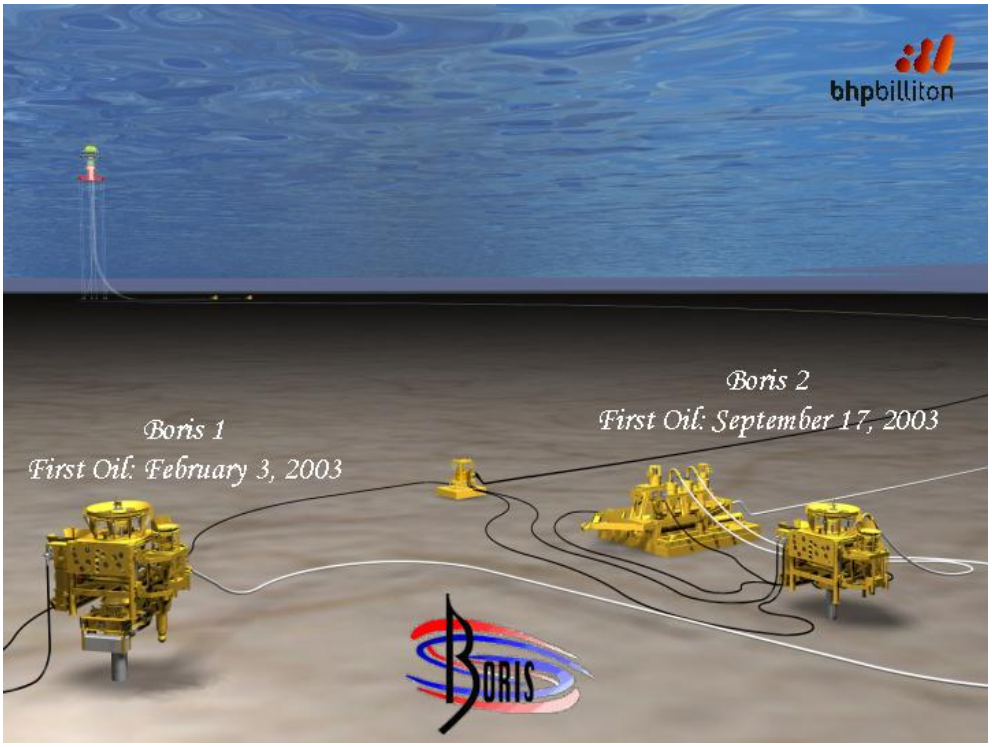


**Figure 1**
**Boris Development Project**

| ID | Task Name | Start | Finish |
|---|---|---|---|
| 1 | **Project Milestones** | **Wed 8/1/01** | **Mon 2/3/03** |
| 2 | **Project Sanction** | **Tue 2/12/02** | **Tue 2/12/02** |
| 3 | Development Plan Approved | Tue 6/18/02 | Tue 6/18/02 |
| 4 | Typhoon PHA Approved | Mon 9/9/02 | Mon 9/9/02 |
| 5 | Begin Tree/Controls SIT | Fri 7/26/02 | Fri 7/26/02 |
| 6 | Begin Boris-1 Completion | Sun 8/18/02 | Sun 8/18/02 |
| 7 | Begin Flowline/Manifold Installation | Wed 8/1/01 | Wed 8/1/01 |
| 8 | **First Oil #1 Well** | **Mon 2/3/03** | **Mon 2/3/03** |
| 9 | **Discovery Well** | **Mon 8/6/01** | **Mon 10/29/01** |
| 14 | **Concept Phase** | **Wed 8/1/01** | **Thu 1/3/02** |
| 17 | **FEED Phase** | **Wed 8/1/01** | **Mon 12/17/01** |
| 56 | Development Sanction | Tue 2/12/02 | Tue 2/12/02 |
| 57 | **Execution Phase** | **Mon 10/1/01** | **Tue 2/11/03** |
| 58 | **Partner Agreements** | **Tue 2/12/02** | **Mon 9/9/02** |
| 59 | Review/Approve Field Development Plan | Tue 2/12/02 | Thu 8/22/02 |
| 60 | Review/Approve Fabrication AFE | Tue 2/12/02 | Fri 6/28/02 |
| 61 | Negotiate Typhoon PHA | Tue 2/12/02 | Mon 9/9/02 |
| 62 | **Regulatory Approvals** | **Sun 3/3/02** | **Tue 10/22/02** |
| 75 | **HSE Activities** | **Mon 2/11/02** | **Thu 12/26/02** |
| 89 | **Operations Activities** | **Mon 2/11/02** | **Mon 2/3/03** |
| 137 | **Completion Hardware Procurement** | **Mon 1/28/02** | **Wed 7/10/02** |
| 158 | **Subsea Equipment Fabrication** | **Fri 2/8/02** | **Mon 11/11/02** |
| 159 | **Production Controls** | **Thu 2/14/02** | **Mon 11/11/02** |
| 160 | Award Order to ABB | Thu 2/14/02 | Thu 2/14/02 |
| 161 | Issue PO | Fri 7/12/02 | Fri 7/12/02 |
| 162 | **Topsides Controls Equipment** | **Thu 2/14/02** | **Mon 11/11/02** |
| 166 | **Subsea Controls Equipment** | **Thu 2/14/02** | **Mon 9/23/02** |
| 182 | **Subsea Tree & Peripherals** | **Fri 2/8/02** | **Mon 7/29/02** |
| 183 | Award Order to Cameron | Fri 2/8/02 | Fri 2/8/02 |
| 184 | Issue PO | Mon 7/15/02 | Mon 7/15/02 |
| 185 | Subsea Tree Mods | Wed 2/20/02 | Mon 7/29/02 |
| 186 | Production Stab & Hinge Over System | Wed 2/20/02 | Thu 7/25/02 |
| 187 | Umbilical Stab & Hinge Over System | Wed 2/20/02 | Thu 7/25/02 |
| 188 | Completion Guidebase | Wed 2/20/02 | Thu 7/25/02 |
| 189 | **Subsea Manifold** | **Wed 5/22/02** | **Tue 10/1/02** |
| 190 | Award Order | Wed 5/22/02 | Wed 5/22/02 |
| 191 | Issue P.O. | Mon 7/15/02 | Mon 7/15/02 |
| 192 | Valves - Berwick | Wed 5/22/02 | Thu 8/15/02 |
| 193 | Fab Frame, Install Valves, & Insulate | Sat 7/13/02 | Tue 10/1/02 |
| 194 | **Umbilical, Flowline & Jumper Fabrication** | **Tue 1/22/02** | **Sat 10/5/02** |
| 195 | **Umbilical** | **Tue 1/22/02** | **Sat 10/5/02** |
| 196 | Award Order to Multiflex | Tue 1/22/02 | Tue 1/22/02 |
| 197 | Issue PO | Mon 7/15/02 | Mon 7/15/02 |
| 198 | Design | Tue 2/12/02 | Mon 7/1/02 |
| 199 | Fabricate | Sat 5/4/02 | Thu 6/6/02 |
| 200 | Spool | Thu 6/6/02 | Fri 6/7/02 |
| 201 | Ship to Carlyss | Tue 8/6/02 | Mon 9/2/02 |
| 202 | Terminations @ Carlyss | Sat 9/28/02 | Sat 10/5/02 |
| 203 | **Hard Pipe** | **Mon 2/25/02** | **Tue 10/1/02** |
| 204 | Detailed Design | Mon 2/25/02 | Fri 4/26/02 |
| 205 | Award Order to US Steel | Fri 4/12/02 | Fri 4/12/02 |
| 206 | Manufacture Pipe | Mon 5/20/02 | Fri 7/19/02 |
| 207 | Ship to Insulator | Fri 8/2/02 | Fri 8/23/02 |
| 208 | **Insulation/Coating** | **Tue 7/9/02** | **Tue 10/1/02** |
| 209 | Award Order | Tue 7/9/02 | Tue 7/9/02 |
| 210 | Issue P.O. | Wed 9/4/02 | Wed 9/4/02 |
| 211 | Insulate/Coat pipe | Thu 9/5/02 | Tue 10/1/02 |
| 212 | **Flex Pipe/Jumper** | **Fri 4/12/02** | **Tue 10/1/02** |
| 213 | Award to NKT | Fri 4/12/02 | Fri 4/12/02 |
| 214 | Design | Mon 4/22/02 | Tue 7/2/02 |
| 215 | Flex Pipe Manufacture | Wed 5/1/02 | Fri 8/2/02 |
| 216 | Ship Jumper to Houston | Mon 8/19/02 | Wed 9/4/02 |
| 217 | Truck Jumper to Carlyss | Mon 9/9/02 | Wed 9/11/02 |
| 218 | Ship Flex Pipe to Carlyss | Tue 9/3/02 | Tue 10/1/02 |
| 219 | **Topsides** | **Mon 10/1/01** | **Sun 9/15/02** |
| 220 | **Design Engineering** | **Wed 2/13/02** | **Thu 8/15/02** |
| 226 | **Procurement** | **Tue 3/5/02** | **Fri 5/24/02** |
| 231 | **Fabrication** | **Tue 3/5/02** | **Fri 9/13/02** |
| 237 | **Documentation** | **Mon 10/1/01** | **Sun 9/15/02** |
| 240 | **SIT** | **Fri 7/26/02** | **Sat 10/5/02** |
| 241 | Tree/Controls (Berwick) | Fri 7/26/02 | Wed 8/14/02 |
| 242 | Manifold & Flex Jumper (Carlyss) | Tue 10/1/02 | Sat 10/5/02 |
| 243 | **Rig Activities** | **Fri 5/3/02** | **Sat 11/23/02** |
| 244 | AGIP Well Completion | Fri 5/3/02 | Sun 8/18/02 |
| 245 | Stand by | Sun 8/18/02 | Sun 8/18/02 |
| 246 | Complete Boris 1 | Sun 8/18/02 | Sat 11/23/02 |
| 247 | **Installation** | **Sun 7/7/02** | **Sun 1/26/03** |
| 248 | **Topsides** | **Sun 7/7/02** | **Tue 12/24/02** |
| 280 | **Flowline/Umbilical** | **Wed 11/27/02** | **Sun 1/26/03** |
| 281 | Spool | Wed 11/27/02 | Fri 11/29/02 |
| 282 | Mob Chickasaw to Site | Sun 12/1/02 | Tue 12/3/02 |
| 283 | Riser Pull-in | Fri 12/6/02 | Sat 12/7/02 |
| 284 | Install Flowline/Manifold | Sat 12/7/02 | Wed 12/18/02 |
| 285 | Load Umbilical & Flying Leads | Sat 12/21/02 | Thu 12/26/02 |
| 286 | Umbilical Installation Re-Planning Period & Remot | Wed 1/8/03 | Sat 1/18/03 |
| 287 | Umbilical Pull-in | Sat 1/18/03 | Sun 1/19/03 |
| 288 | Install Main & Infield Umbilicals | Sun 1/19/03 | Sat 1/25/03 |
| 289 | Demob Chickasaw | Sat 1/25/03 | Sun 1/26/03 |
| 290 | Pre-Commissioning | Tue 1/21/03 | Thu 1/30/03 |
| 291 | Commissioning | Thu 1/30/03 | Mon 2/3/03 |

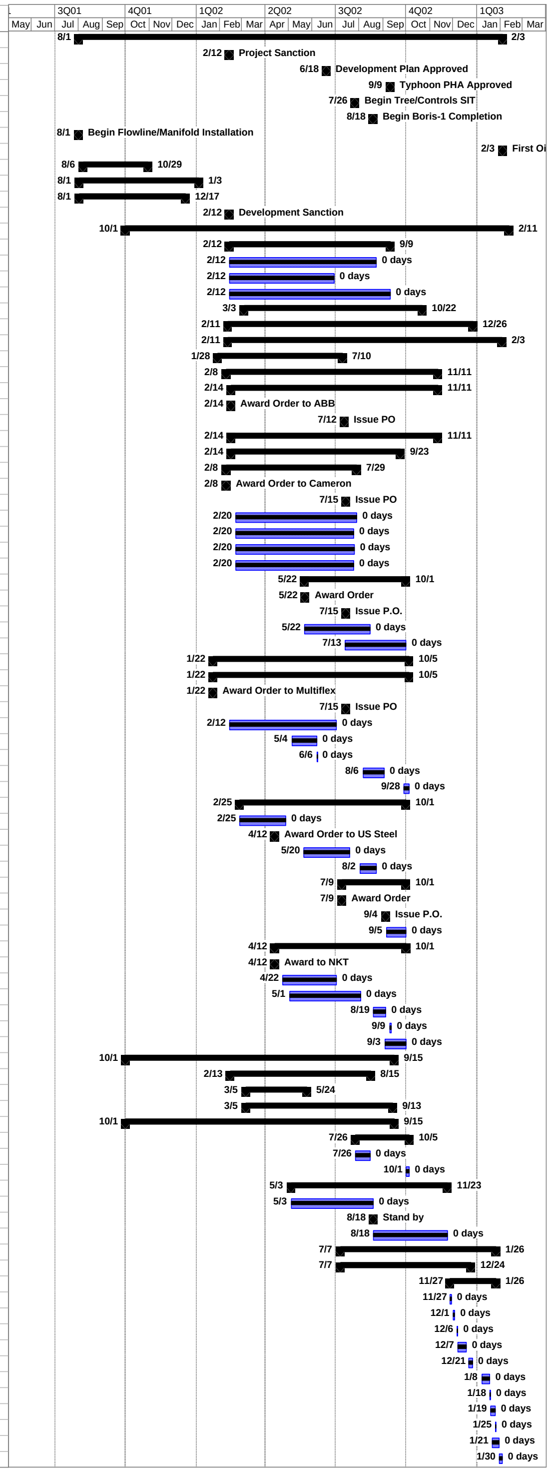


**Figure 2**
**Boris 1 Level 1 Project Schedule (Actual)**