Celtic Exploration Ltd.

Application for Common Carrier and Common Processor Orders Otter Field

April 26, 2005

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2005-027: Celtic Exploration Ltd., Application for Common Carrier and Common Processor Orders, Otter Field

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ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

CELTIC EXPLORATION LTD.
COMMON CARRIER AND COMMON PROCESSOR **Decision 2005-027**
OTTER FIELD **Application No. 1360900**

1 DECISION

Having carefully considered all of the evidence, the Alberta Energy and Utilities Board (EUB/Board) grants Application No. 1360900, subject to the approval of the Lieutenant Governor in Council, with the forms of the orders as shown in Appendix 2 in accordance with the discussion noted below.

2 APPLICATION, INTERVENTION, AND HEARING

Celtic Exploration Ltd. (Celtic) applied

- under Section 48(1) of the *Oil and Gas Conservation Act* (the Act) for an order declaring Tempest Energy Corp. (Tempest) as a common carrier of gas from an undefined Banff pool in the Otter Field (the subject pool), through a pipeline extending from a tie-in point at Legal Subdivision 2 of Section 22, Township 88, Range 12, West of the 5th Meridian (LSD 2-22-88-12 W5M) to the Tempest Red Earth gas plant located in LSD 2-23-88-8 W5M (the Red Earth gas plant), including a compressor at LSD 15-15-88-12 W5M (the 15-15 compressor) (see Figure 1);
- under Section 53(1) of the Act for an order declaring Tempest to be a common processor of gas produced from the subject pool through the Red Earth gas plant;
- under Sections 48(4)(b) and 53(5)(a) of the Act for the EUB to allocate the proportion of production to be taken by the common carrier and common processor from the subject pool; and
- under Section 56 of the Act for the above-noted orders to be effective as of the date of the application, September 14, 2004.

Tempest filed a submission opposing the application.

The application was considered at a public hearing in Calgary, Alberta, on January 20 and 21, 2005, before Acting Board Members F. Rahnama, Ph.D. (Presiding Member), R. J. Willard, P.Eng., and R. G. Evans, P.Eng. Those who appeared at the hearing are listed in Appendix 1.

3 BACKGROUND

The Tempest wells located in LSDs 9-10, 2-14, 14-15, 2-22, 3-26, and 5-27-88-12 W5M (the 2/9-10, 2-14, 14-15, 2-22, 3-26, and 5-27 wells respectively) were drilled between 1987 and 2002 and encountered productive reservoir in the Detrital zone and the Banff Formation. The wells were placed on production in March 2004, with sweet gas flowing to the Red Earth gas plant for processing.

The Red Earth gas plant is a sour gas processing plant with inlet compression and amine sweetening.

Celtic drilled its well in LSD 4-23-88-12 W5M (the 4-23 well) in July 2004. This well and the Tempest 2/9-10, 2-14, 2-22, and 5-27 wells are off-target in a one-section drilling spacing unit for production from the subject gas pool.

The 4-23 well is currently not tied into any gathering system.

4 ISSUES

The Board considers the issues respecting the application to be

- the delineation of the subject pool
- the need for common carrier and common processor orders, and if the orders are issued, the details of the orders, and
- the need for an order allocating production, and if the order is issued, the details of the order.

In addition, the parties raised the issue of wells in the subject pool being off-target.

The Board has indicated in previous decision reports that a successful applicant for common carrier and common processor orders would be required to satisfactorily demonstrate that

- producible reserves are available for transportation and processing and that processing facilities are needed;
- there is a reasonable expectation of a market for the gas that is to be transported and processed through the proposed common carrier and common processor facilities;
- reasonable arrangements for use of the pipeline and processing facilities could not be agreed on by the parties; and
- the common carrier and common processor orders represent the only economic way or clearly the most practical way to transport and process the gas in question, or are clearly superior environmentally.

The panel believes that these criteria continue to be applicable in this case.

5 DELINEATION OF THE SUBJECT POOL

5.1 Views of Celtic

Celtic interpreted the reservoir of interest to be comprised of two zones—a Banff carbonate that may have been dolomitized in some locations, and a deposit above the Banff carbonate that may be Detrital, Bluesky, Gething, or altered Banff in nature (hereafter referenced as Detrital). The applicant was not certain if the Detrital and Banff carbonate deposits were separate reservoirs, because in some locations, such as at the 3-26 well, there appeared to be separation of the zones, but in other locations, such as at the 4-23 well, the Detrital deposit lies directly on the Banff carbonate.

The applicant assigned net pay to only the Banff carbonate zone. To obtain the net pay values for wells in the subject pool, Celtic used a resistivity of about 20 ohms, a 5 per cent (%) limestone porosity cutoff, and a gas/water contact 140 metres (m) above sea level, which it estimated from well log and productivity data. Celtic argued that Tempest had failed to demonstrate that there was bitumen or heavy oil plugging in the 4-23 well or in offsetting sections, which would justify reducing the net pay values in some wells as Tempest had done. The applicant noted that it did not test the Detrital and Banff perforations in the 4-23 well separately, but since perforations from both intervals accepted acid during stimulation, it assumed that gas was flowing from both zones during testing. Celtic questioned whether it was possible to accurately calculate water saturation for each well because of the presence of heavy oil or bitumen, and it used a constant water saturation in its evaluations. The applicant's net pay, porosity, and water saturation values for the wells of interest are shown in Table 1. The applicant mapped the subject pool as shown in Figure 2, with its 4-23 well in a common reservoir with the Tempest 2/9-10, 2-14, 14-15, 2-22, 3-26, and 5-27 wells.

Celtic estimated the original gas in place for the subject pool by material balance to be 120 million cubic metres (10^6 m^3) and by volumetric analysis to be 303 10^6 m^3. The applicant considered the material balance reserves estimate to be more accurate. It indicated that the mapping may be optimistic. Some of the pay assigned could be plugged with heavy oil or bitumen, or the gas affect on the density porosity log may result in interpreted porosity values being higher than actual porosity, especially in wells with porosities higher than 10%.

Celtic estimated a reserve life index for the pool of about 0.9 year using a constant rate of production based on pool data for September 2004. The applicant noted that it was difficult to assess what the production decline and thus overall reserves life would be, but suggested that the pool could produce for two or more years, accounting for decline.

5.2 Views of Tempest

Tempest interpreted two productive zones associated with the Banff Formation in the Otter area—a Banff deposit comprising interbeded limestones, dolomitic limestones, and shales, and a Detrital zone derived from Banff deposits lying on top of the Banff limestone. It considered the Detrital and Banff carbonate deposits to be in natural communication in many wells, since the Detrital zone is directly on top of the Banff carbonate or is separated by very thin shales of unknown continuity.

Tempest evaluated the Detrital and Banff carbonate zones separately. It used a 6% limestone porosity cutoff and a 12% porosity cutoff for the Detrital zone to determine net pay. Tempest did not recognize any productive Banff carbonate pay in Celtic's 4-23 well. It argued that the gas flow during testing of the 4-23 well came from the Detrital zone only and that a comparison of well logs for the 4-23 and 3-26 wells suggested that the Banff carbonate porosity in the 4-23 well was plugged with bitumen and was not productive. Tempest agreed with the applicant that there was an aquifer in the pool, but it did not attempt to calculate a gas/water contact due to the erratic resistivities on the well logs caused by bitumen or heavy oil in the zones. For the same reason, Tempest used a constant water saturation for each of the Detrital and Banff carbonate deposits in its evaluations. The intervener's net pay, porosity, and water saturation values for the wells of interest are shown in Table 1. It mapped the Detrital and Banff carbonate pools of interest as shown in Figure 2, with the Celtic 4-23 well included in the same Detrital pool as the Tempest producing wells but excluded from the Banff carbonate pool.

Tempest estimated the total original gas in place reserves by volumetric analysis for the Detrital and Banff carbonate pools to be 505 10^6 m^3. Tempest did not conduct a material balance analysis or comment on Celtic's material balance reserves estimate for the pool.

The intervener did not have an estimate of the life for the subject pool but speculated that it would be twice as long as that estimated by Celtic.

5.3 Views of the Board

The Board notes that the parties are in agreement that there are two productive horizons in the wells of interest—a Banff carbonate and a Detrital deposit. Considering that the Detrital zone is directly on top of the Banff carbonate or is separated by thin shales of unknown continuity in several wells, the Board considers that the two zones are in natural communication and should be defined as a single pool.[1]

The Board has reviewed the information filed to determine the probable edges of the pool. The Board determines that Celtic's 5% limestone porosity and a gas/water contact of 140 m above sea level are reasonable cutoffs to determine net pay. The Board also notes that both parties interpret the productive Banff carbonate to be confined to a limited number of units that subcrop against the Banff unconformity. Tempest referred to these units as carbonate ramp deposits. The Board accepts that below these units the Banff does not appear to be productive and bitumen plugging was suggested as a possible reason. The Board agrees with Celtic that the bottom productive unit is still present in the 4-23 well.

In all cases, the True Vertical Depth logs were used, and pay was assigned to clean Banff carbonate as determined from the resistivity, gamma ray, and porosity logs, and to the Detrital zone if gas was recovered when tested or if the zone was present above the productive Banff carbonate unit and met the cutoffs. The Board agrees with the parties that water saturation is difficult to determine due to the influence of residual bitumen or heavy oil on the resistivity well logs. The Board accepts Tempest's water saturation values of 55% and 40% for the Banff carbonate and Detrital zone respectively as reasonable. In any section where there is a well that is excluded from the pool and a well that is included in the pool, the Board's pool order will include the entire section. However, for the purposes of this hearing, the Board believes it is appropriate to recognize that reserves are not likely to underlie some portion of the sections involved, as discussed below and later in the report in the context of allocation of production.

The Board recognizes pay in all of the wells in Sections 10 and 11-88-12 W5M and in the well in LSD 4-12-88-12 W5M. However, in the Board's view, there is no Detrital or Banff carbonate pay present in the wells in LSDs 11-12, 16-14, 2-23, or 11-23-88-12 W5M. This places the pool's easterly edge to the west of these wells. There is pay in the 2-14 well and in all of the wells in Sections 15 and 22-88-12 W5M. The Board has interpreted both Detrital and Banff carbonate pay in the 4-23 well. The Board has interpreted only Detrital pay in the 3-26 well and

[1] Where there is natural communication between two deposits, the two deposits would act as one reservoir and would be defined as a single pool. Perforations in the two different deposits in a well would be in the same pool, and on that basis there would be no need to obtain an EUB approval to commingle production from the two deposits.

considered that the pay likely does not extend to the entire section because of the potentially variable nature of the Detrital deposit combined with the absence of the underlying productive Banff carbonate. The Board saw pay in the 5-27 well, with no indication that reserves do not extend over most of the section. No Detrital or Banff carbonate pay is interpreted in the wells in LSDs 16-20 and 5-21-88-12 W5M, which places the pool's westerly edge to the east of that submitted by Tempest. The Board's net pay, porosity, and water saturation values for the wells of interest are shown in Table 1.

Having consideration for the above, the Board order defining the subject pool will include the sections outlined in Figure 2.

The Board notes the differences in the pool interpretations and reserves estimates between the parties and the difference between Celtic's material balance and any of the volumetric reserves estimates. These differences suggest to the Board that there is still considerable uncertainty about the interpretation of the pool.

The Board also notes that while the parties were not able to provide firm estimates for the life of the subject pool accounting for production decline, it is clear that the pool life is likely to be relatively short.

6 NEED FOR COMMON CARRIER AND COMMON PROCESSOR ORDERS AND IF THE ORDERS ARE ISSUED, THE DETAILS OF THE ORDERS

6.1 Views of Celtic

Celtic submitted that the reserves associated with its 4-23 well were being drained by ongoing production from the Tempest wells completed in the subject pool. The applicant filed evidence showing that the reservoir pressure at the 4-23 well in August 2004 was 3165 kilopascals absolute (kPaa), lower than the initial pressure of the pool of 4162 kPaa. It also submitted a static gradient pressure test conducted in January 2005 on the 4-23 well that showed the pressure to be 2569 kPaa, indicating that drainage of reserves at the 4-23 well had continued between August 2004 and January 2005. On the basis of the premise that its share of pool reserves was 12%,[2] Celtic calculated that 2.7 10^6 m^3 of gas had been drained from its lands from September 2004 to January 2005.

The applicant submitted that its evidence showed that producible gas reserves were available for transporting and processing and that processing facilities were needed. Celtic presented its interpretation of the pool as discussed in Section 5.1 of the report, and further submitted that the 4-23 well was capable of production. It noted that a deliverability test conducted on the well in August 2004 resulted in a sandface absolute open flow potential (AOFP) of 37 thousand cubic metres per day (10^3 m^3/d) and a wellhead AOFP of 25 10^3 m^3/d. The applicant submitted that the well continued to clean up during the test, with increasing gas rates and decreasing water production during the test. Celtic submitted data showing that during the first 17 hours of its flow test, the well produced 1.5 m^3 of water per 10^3 m^3 of gas, while in the final 9.5 hours of the test, the well produced 0.5 m^3 of water per 10^3 m^3 of gas. It anticipated that water production from the

[2] Celtic subsequently recalculated its share of pool reserves to be 15%, as discussed in Section 7.1 of the report, but it did not estimate the volume of gas drained from its lands using the revised share of reserves.

well would decrease with production as the drilling and stimulation fluids were fully recovered and would stabilize at similar volumes to those produced by the Tempest wells.

Celtic stated that it had markets for the gas producible from the 4-23 well.

The applicant's evidence was that there were only two alternatives to get its gas to market. It could use the Tempest facilities (the proposed common carrier pipeline, including the 15-15 compressor and the Red Earth gas processing plant), or it could build a pipeline to tie in its gas at LSD 1-26-89-10 W5M (see Figure 1) to the system operated by Devon Canada Corporation (Devon). Celtic considered the Devon tie-in to be uneconomic and environmentally unacceptable, as it was more than 25 kilometres from the 4-23 well and would require construction of a major river crossing. The applicant therefore attempted to obtain satisfactory transportation and processing service from Tempest.

Celtic submitted that its attempts to obtain transportation and processing capacity began in May 2004 and continued into January 2005. The applicant considered an offer from Tempest in September 2004 for best efforts transportation and processing service for a fee of $\$68.51/10^3\ m^3$ (\$1.93/thousand cubic feet [mcf]) of gas with tie-in downstream of the 15-15 compressor. The applicant rejected this proposal for three reasons: first, the fee was too high; second, firm service was required to alleviate drainage of the reserves associated with the 4-23 well; and third, without a commitment of firm service, it was not prepared to undertake the capital investment required to construct a gathering line to tie in its well if it was not able to produce due to capacity restrictions in the system. In response to the Tempest offer, Celtic made a counter-offer to pay $\$36.88/10^3\ m^3$ (\$1.04/mcf) of gas to Tempest for firm service with tie-in upstream of the 15-15 compressor. The applicant's proposed fee was based on its own estimation of current pipeline, compression, and operating costs in the area. This offer was rejected by Tempest.

Celtic considered a subsequent offer from Tempest in December 2004 for firm service for $\$44.37/10^3\ m^3$ (\$1.25/mcf) of gas with tie-in downstream of the 15-15 compressor to be more reasonable, but it did not accept the offer. It stated that the offered fee was still high because Tempest had not allocated the cost of the system over its various producing properties in the area or taken into consideration that Celtic's gas was sweet and did not need the use of the sour gas processing capability of the Red Earth gas plant. Celtic also submitted that with ongoing drainage of its reserves, it now considered tie-in upstream of the 15-15 compressor to be critical to the project's economics. In its view, it would be wasteful and unnecessary to have two compressors serving the subject pool. Celtic further stated that the December 2004 offer was unacceptable because it did not address past drainage of its reserves.

The applicant also noted that Tempest did not concede that there was capacity in the pipeline and the gas processing plant until December 2004 or that there was capacity in the 15-15 compressor until the hearing.

Celtic concluded that it had made reasonable efforts to obtain satisfactory arrangements for the transportation and processing of its gas, but as these efforts were unsuccessful, common carrier and common processor orders were needed.

The applicant requested that the common carrier and common processor orders be made effective on September 14, 2004, the date of its application. It submitted that the requested effective date was justified because it had demonstrated that the 4-23 well was capable of production prior to the date of the application, it had been prevented from producing its well as a result of the unreasonable position of Tempest, and its reserves continue to be drained. It also requested immediate interim relief due to the rapid ongoing depletion occurring from the pool. The applicant stated that it had not built any pipeline to tie the 4-23 well into the Tempest system because it did not have any agreement with Tempest on the tie-in point.

6.2 Views of Tempest

Tempest did not dispute that the reserves associated with Celtic's 4-23 well were being drained by ongoing production from Tempest's wells, that producible gas reserves were available for transporting and processing, that processing facilities were needed, or that there was a market for the gas from Celtic's well. In addition, Tempest did not argue that a new pipeline or plant should be built to handle gas from the 4-23 well or that the gas should flow to any plant other than the Red Earth plant.

Tempest submitted, however, that Celtic had not been prevented from accessing the pipeline in question or the Red Earth gas plant, both of which had capacity for Celtic's gas. The intervener maintained that its offer to Celtic of September 30, 2004, for best efforts service, with tie-in downstream of the 15-15 compressor, for $68.51/10^3 m^3 ($1.93/mcf) of gas was calculated using JP 95 methodology[3] and was fair and reasonable. Tempest further stated that Celtic's counter-offer of $36.88/10^3 m^3 ($1.04/mcf) of gas was based on incorrect capital costs, failed to include lost gas allowance, and used an incorrect rate of return before tax of 12% and therefore did not appear to have been calculated in accordance with JP 95 guidelines. Tempest also argued that its offer to Celtic of December 17, 2004, of $44.37/10^3 m^3 ($1.25/mcf) of gas with tie-in downstream of the 15-15 compressor was well below fees calculated using JP 95 methodology and furthermore provided the firm service requested by Celtic. In response to Celtic's submission that it should not need to pay for use of the sour gas processing portion of the Red Earth gas plant, Tempest stated that the plant was not broken into functional units, so there was no differentiation between compression, sweetening, dehydration, or inlet separation. The plant was one functional unit from the standpoint of capital and operating costs.

Tempest acknowledged that it had indicated to Celtic from the time of initial discussions with Celtic that there was no capacity in the 15-15 compressor, but that just prior to the hearing it had determined that the compressor was not fully used. However, it argued that it had always intended to use all available capacity and its wells had the deliverability to fill the compressor. It submitted that reducing its own access to the compressor to accommodate Celtic gas would adversely affect its planning for efficient operation. Tempest considered that Celtic could install its own rental compressor, which would be inexpensive and could be installed quickly. If Celtic's economics were not favourable without use of the 15-15 compressor, this was a function of the poor quality of the 4-23 well rather than Tempest not making any reasonable offers. The intervener submitted that the test information for the 4-23 well indicated a wellhead AOFP of only about 25 10^3 m^3/d and a water/gas ratio of 0.626 $m^3/10^3$ m^3 (111 barrels/million cubic feet [mmcf]). Tempest was of the opinion that the salinity of the water produced from the 4-23 well indicated that the well was producing formation water and not cleaning up, as argued by Celtic.

[3] The JP 95 methodology for calculating fees is set out in the report *Joint Task Force Report on Processing Fees, April 15, 1996*, a joint report by the Canadian Association of Petroleum Producers, the Petroleum Joint Venture Association, and the Small Explorers and Producers Association of Canada.

In Tempest's view, water production from the 4-23 well would not decrease when the well was placed on production.

Tempest argued that it was not required to provide optimum economics for Celtic's well, which was a poor one, but only a reasonable opportunity to produce. It maintained that it had made reasonable offers to Celtic and therefore the application should be denied. For the same reasons, the Board should deny the interim relief requested by Celtic.

Tempest opposed the application, but submitted that if any order were issued, it should be limited to the 15-15 compressor, as Tempest had never denied Celtic access to the pipeline and plant. In addition, Tempest stated that if any orders were issued, they should not be made retroactive, because Celtic had not been and was still not in a position to produce its well. Tempest considered that Celtic could have licensed and built a pipeline to tie in the 4-23 well, but did not do so. On that basis, any orders issued should be effective on the date Celtic tied in the 4-23 well. Alternatively, if any order were granted by the Board, it should not be effective before October 19, 2004, the date that Celtic provided the additional information that should have been included in the initial application filed.

6.3 Views of the Board

The Board accepts the evidence and statements that producible reserves are available for transportation and processing from the 4-23 well, that processing facilities are needed, and that the applicant has a market for the gas. The Board also notes that there was no evidence presented to indicate that other pipelines and gas plants should be considered as an alternative to the proposed common carrier and processor facilities. Further, the Board observes that there is no dispute that the reserves associated with the 4-23 well are being drained by production from other wells in the pool and accepts that such drainage has occurred and continues to take place.

The Board considers that Celtic made reasonable attempts to negotiate transportation arrangements respecting its gas. In particular, given the drainage situation, the Board is concerned regarding the lack of an early offer of firm service and the absence of verification of compressor capacity. The Board is also concerned that while both parties used JP 95 to calculate fees, the parties did not exchange information early in the discussions and therefore did not calculate consistent fees, making the JP 95 methodology ineffective as a tool for negotiations. The Board observes that the parties continued to communicate regarding possible arrangements before and after the application was filed but were unable to come to any mutually satisfactory agreement. In particular, Tempest declined to provide any capacity for Celtic gas in the 15-15 compressor, the parties did not come to any agreement respecting Celtic's share of pool production, and Tempest did not offer to address past drainage of Celtic's gas.

In reviewing whether it would be reasonable for Celtic to use the existing 15-15 compressor, the Board notes that

- at the time of the hearing, there was capacity in the compressor;
- the life of the subject pool is likely to be very short, and it is reasonable to expect that well productivity will decline, allowing additional capacity in the compressor;
- the Celtic gas that would enter the system is from a single well only; and

- the Celtic share of gas produced from the pool is not large in comparison with the volume produced from the entire pool (see discussion below).

On the basis of the foregoing, the Board concludes that the most practical way to handle Celtic's gas would be to flow it through the 15-15 compressor to the subject pipeline to the Red Earth gas processing plant. The Board is accordingly prepared to approve the common carrier and processor applications. The Board notes Tempest's request that any order issued apply only to the 15-15 compressor. However, the Board is of the view that such an order would not ensure that Celtic has access to all of the facilities needed to deliver its gas to the processing plant.

In determining the effective date of the common carrier and common processor orders, the Board considered the detrimental effects to the applicant caused by the delay between the time the application was made and its disposition and the applicant's diligence in preparing its well for production and filing a complete application.

The Board notes that the applicant tested its well to confirm its capability. The Board accepts that the lack of an agreement on the tie-in point made the construction of a pipeline problematic. Further, in the months between September 2004, when the application was filed, and January 2005, there was a significant decline in pressure at the 4-23 well of some 600 kPaa, and it is likely that the pressure continues to decline. On that basis, the Board believes that it is appropriate that the common carrier and common processor orders be made effective prior to the date of the issuance of the orders. The Board notes that Celtic is responsible for part of the time taken to process the application because it filed an incomplete application, which was not completed until October 19, 2004. The Board therefore believes that an appropriate effective date for the common carrier and processor orders would be the date the application was complete, October 19, 2004. Given that the orders are to have a retroactive effect, the Board does not see any need to provide the interim relief requested by Celtic.

The Board notes that although there was discussion respecting the fees to be paid for transporting and processing Celtic's gas, the applicant did not request that the Board set these fees. If the parties are unable to come to an agreement on fees, either party may apply to the Board to set the fees.

7 NEED FOR AN ORDER ALLOCATING PRODUCTION AND IF AN ORDER IS ISSUED, THE DETAILS OF THE ORDER

7.1 Views of Celtic

Celtic's evidence was that the two parties had differing opinions on Celtic's share of pool production, and therefore an allocation of production among wells in the pools was needed. The applicant calculated its share of pool production to be 15% on the basis of net pay, porosity, and gas saturation, with one section assigned as a validated area to the 4-23 well and to each of the producing Tempest wells. Celtic considered that its 4-23 well was on target and did not address any possible reduction in the share of production due to the location of the well.

The applicant requested that the allocation be on a well-by-well basis and that production be balanced in accordance with the allocated percentages on a quarterly basis. Celtic also said that it would welcome the concept of the allocation order having a minimum rate that would allow each party to produce at some volume, even if the other operator shut in production for any reason. The applicant suggested that on the basis of economics and operating efficiency, a rate of 28 10^3 m^3/d (1 mmcf/d) be assigned as the minimum rate that would flow through the 15-15 compressor, with that total volume being divided among wells, resulting in a minimum rate per well.

7.2 Views of Tempest

Tempest opposed the issuance of any order allocating production among wells in the pool. However, in the event that such an order were issued, Tempest submitted that the allocation should be based on its mapping of the two productive zones involved. Using these maps, it calculated that Celtic's share of production was 1% of total pool production. Tempest also argued that the area used to calculate Celtic'share of production should be reduced to account for the well being off-target in its drilling spacing unit, but it did not put forward any specific calculations of a reduced share of production. Tempest did not suggest an allocation calculated using the same formula that Celtic used, but substituting Tempest's own wellbore parameters and validated areas. However, it provided its opinion on what validated areas should be assigned to each well if such a formula were used, as set out in Table 1.

Tempest said that any allocation should be made on a company basis, not on a well-by-well basis, and that production should be balanced on a quarterly basis in accordance with the allocated percentages. Tempest also indicated that it would like minimum rates set that would allow each party to produce at some volume, even if the other operator shut in or reduced production for any reason. It suggested that this minimum be set on a company basis and be in the order of 28 to 42 10^3 m^3/d (1 to 1.5 mmcf/d).

7.3 Views of the Board

The Board notes the difference in opinion between the parties about Celtic's share of pool production and agrees that there is a need to allocate production.

In considering the question of allocation, the Board observes, as noted above, that there is still considerable uncertainty in interpreting the pool. Accordingly, the Board does not believe that detailed mapping should be used as the basis for the allocation. The Board notes that Celtic used an allocation formula that incorporates wellbore parameters (net pay, porosity, and water saturation) over validated areas in a manner consistent with the formula used in previous decisions by the Board on allocation matters. The Board believes that this formula is an appropriate starting point in this case.

The Board considers that the allocation should account for the Detrital and Banff carbonate wellbore parameters in the subject wells. The Board notes that the parties used consistent water saturations. The resulting formula used by the Board incorporates net pay, porosity, and validated areas, as shown in Table 1.

In determining the validated areas to be assigned to each well, the Board used its pool outline, as set out in Figure 2, as a basis for the maximum possible limit for the validated areas, as modified by existing well control. The Board considered that the validated areas should account for gas that could be drained by existing producing wells. In addition, a validated area should include only those tracts where there is a reasonable likelihood that there are recoverable reserves.

Quarter, half, whole, and multiple section validated areas were used to address these issues. The Board did not consider it useful to assign validated areas separately to the Detrital deposit and Banff carbonate, as the two intervals are considered to be in natural communication.

On the basis of the foregoing, the Board considers that the 2/9-10 well validates Sections 10 and 11-88-12 W5M. The 14-15, 2-22, and 5-27 wells each validate the entire sections involved. The 2-14 well validates only three-quarters of the section, because of the presence of the well in LSD 16-14-88-12 W5M, where there are no Detrital or productive Banff carbonate deposits. The 4-23 well would validate only one-quarter of the section, again because of the lack of any Detrital or productive Banff carbonate deposits in the wells in LSDs 2-23 and 11-23-88-12 W5M. The 3-26 well only validates half of the section, because of the potentially variable nature of the Detrital deposit combined with the absence of the underlying productive Banff carbonate, as noted previously.

The Board used the above-noted validated areas and its own evaluations of the net pay and porosity (discussed in Section 5) in the allocation formula, as shown in Table 1, resulting in the well-by-well allocations shown in the table. However, the Board is of the view that it would be unnecessarily onerous to Tempest to allocate production on a well-by-well basis and therefore has decided that the allocation should be on a company basis. The resulting allocation provides 3% of the pool production to Celtic and 97% to Tempest. As this allocation addresses what would be an equitable share of production for the 4-23 well and other wells in the pool, there is no reason to also apply any off-target penalty.

The Board notes that both parties favoured the use of a minimum rate that would allow each party to produce at some volume even if the other operator shut in or reduced production for any reason. The Board considers the minimum rate to be a practical approach and is prepared to include such rates in the order. Celtic suggested that 28 10^3 m^3/d divided among the parties be used as the minimum rate, while Tempest suggested that 28 to 42 10^3 m^3/d be allocated on a company basis. Given that both parties suggested similar methods for determining the minimum rate, the Board is prepared to accept the calculation using the higher minimum of 42 10^3 m^3/d. Applying the allocation of 97% for Tempest and 3% for Celtic results in 40.7 10^3/d of gas as the minimum combined rate for Tempest and 1.3 10^3 m^3/d as the minimum rate for Celtic. Each party may produce up to its minimum rate even if the other party is unable to produce up to its minimum rate.

As noted in Section 6.3, the Board is prepared to issue common carrier and common processor orders effective as of October 19, 2004. Accordingly, the Board considers that the allocation order giving effect to these orders include, in addition to the above-noted provisions for minimum rates and the allocation of production above the minimum rates, a provision to allow Celtic to produce, during the first 3 months after the 4-23 well commences production, its 3% share of the pool production taken by Tempest during the period from October 19, 2004, to the date of commencement of production from the 4-23 well.

The Board notes that the parties are in agreement that balancing production between the parties should be done on a quarterly basis, and the Board also considers this period to be appropriate. The balancing of production must account for Celtic's share of gas production from October 19, 2004, as noted above, and the volume of production above the minimum rates set.

In summary, for the reasons noted above, the Board is prepared to approve the subject application, subject to the approval of the Lieutenant Governor in Council, with the terms and conditions as described.

Forms of Orders to be issued giving effect to these decisions are included in Appendix 2.

Dated in Calgary, Alberta, on April 26, 2005.

ALBERTA ENERGY AND UTILITIES BOARD

(Original signed by)

F. Rahnama, Ph.D.
Presiding Member
Acting Board Member

(Original signed by)

R. J. Willard, P.Eng.
Acting Board Member

(Original signed by)

R. G. Evans, P.Eng.
Acting Board Member

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in report)	Witnesses
Celtic Exploration Ltd. (Celtic) H. D. Williamson, Q.C. D. Watt	A. G. Franks, P.Eng. M. R. Shea G. R. Wilcox, P.Geol. D. J. Wilson C. L. Yu, P.Eng.
Tempest Energy Corp. (Tempest) A. Harvie	D. W. Finley, P.Eng. F. J. Laudel M. A. Malouin, P.Eng. I. C. Moller, P.Eng., of Moller & Associates Ltd. and Gas Processing Management Inc.
Alberta Energy and Utilities Board staff G. D. Perkins, Board Counsel K. Bieber, P.Geol. K. Fisher J. Meckelborg	

APPENDIX 2 FORMS OF ORDERS ISSUED

FORM OF COMMON CARRIER ORDER*

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ALBERTA ENERGY AND UTILITIES BOARD

ORDER NO. Misc ____

An order relating to the production of gas in the

Otter Field

The Alberta Energy and Utilities Board, pursuant to the *Oil and Gas Conservation Act*, being Chapter O-6 of the *Revised Statutes of Alberta, 2000*, and with the approval of the Lieutenant Governor in Council, given by Order in Council, numbered O.C. _____ and dated ________ 2005, hereby orders as follows:

1. Tempest Energy Corp. is a common carrier of gas produced from the Otter Banff A Pool though the pipeline extending from a tie-in point at Legal Subdivision 2 of Section 22, Township 88, Range 12, West of the 5th Meridian to the Tempest Red Earth gas plant located in Legal Subdivision 2 of Section 23, Township 88, Range 8, West of the 5th Meridian, including a compressor at Legal Subdivision 15 of Section 15, Township 88, Range 12, West of the 5th Meridian.

2. This order is effective as of October 19, 2004.

3. Attached to this order is the Order of the Lieutenant Governor in Council authorizing the granting of this order.

MADE at the City of Calgary, in the Province of Alberta, on _______

ALBERTA ENERGY AND UTILITIES BOARD

* This is only a form of order. When issued, the order may have minor variations from that set out here.

FORM OF COMMON PROCESSOR ORDER*

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ALBERTA ENERGY AND UTILITIES BOARD

ORDER NO. Misc ____

An order relating to the production of gas in the

Otter Field

The Alberta Energy and Utilities Board, pursuant to the *Oil and Gas Conservation Act*, being Chapter O-6 of the *Revised Statutes of Alberta, 2000*, and with the approval of the Lieutenant Governor in Council, given by Order in Council, numbered O.C. _____ and dated ________ 2005, hereby orders as follows:

1. Tempest Energy Corp. is a common processor of gas produced from the Otter Banff A Pool though the Red Earth gas processing facilities located in Legal Subdivision 2 of Section 23, Township 88, Range 8, West of the 5th Meridian.

2. This order is effective as of October 19, 2004.

3. Attached to this order is the Order of the Lieutenant Governor in Council authorizing the granting of this order.

MADE at the City of Calgary, in the Province of Alberta, on _______

ALBERTA ENERGY AND UTILITIES BOARD

* This is only a form of order. When issued, the order may have minor variations from that set out here.

FORM OF ALLOCATION ORDER*

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ALBERTA ENERGY AND UTILITIES BOARD

ORDER NO. Misc ____

An order relating to the production of gas in the

Otter Field

The Alberta Energy and Utilities Board, pursuant to the *Oil and Gas Conservation Act*, being Chapter O-6 of the *Revised Statutes of Alberta, 2000*, hereby orders as follows:

1. The well with the unique identifier of 00/04-23-088-12W5/0, hereinafter referred to as the 4-23 well, is entitled to 3 per cent of the total gas production taken from the wells with the unique identifiers of 02/09-10-088-12W5/3, 00/02-14-088-12W5/0, 00-14-15-088-12W5/0, 00/02-22-088-12W5/0, 00/03-26-088-12W5/3, and 00/05-27-088-12W5/0, hereinafter referred to as the Tempest Energy Corp. wells, during the period from October 19, 2004, to the date that the 4-23 well commences production.

2. Within the first 3 months following the commencement of production from the 4-23 well, Celtic Exploration Ltd. shall produce a volume of gas from the Otter Banff A Pool that is equal to its 3 per cent share of past gas production as determined by clause 1 hereof. This gas production is in addition to any other production from the Otter Banff A Pool that Celtic is entitled to under this Order.

3. Beginning on the day that the 4-23 well commences production, the 4-23 well may produce a minimum volume of gas from the Otter Banff A Pool that is equal to 1300 cubic metres multiplied by the number of days remaining in that calendar quarter. Thereafter, the 4-23 well may produce a minimum volume of gas in each subsequent calendar quarter of each year that is equal to 1300 cubic metres multiplied by the number of days in the calendar quarter.

4. Beginning on the day the 4-23 well commences production, the Tempest Energy Corp. wells may produce a minimum volume of gas from the Otter Banff A Pool that is equal to 40 700 cubic metres multiplied by the number of days remaining in that calendar quarter.

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* This is only a form of order. When issued, the order may have minor variations from that set out here.

Thereafter, the Tempest Energy Corp. wells may produce a total minimum volume of gas in each subsequent calendar quarter of each year that is equal to 40 700 cubic metres multiplied by the number of days in the calendar quarter.

5. Beginning on the day the 4-23 well commences production, the total gas production from the Otter Banff A Pool in excess of the minimum volumes set out in clauses 3 and 4 shall be distributed between the 4-23 well and the Tempest Energy Corp. wells in the proportions of 3 and 97 per cent respectively. Such excess gas production shall be balanced on a calendar quarterly basis. In the case of the calendar quarter during which production from the 4-23 well commences, each party's share of production under this clause shall be prorated based on the number of days remaining in the quarter.

6. Production from the Tempest Energy Corp. wells may be taken from any combination of the specified wells.

7. No off-target penalty shall be applied to any well that is subject to this order.

MADE at the City of Calgary, in the Province of Alberta, on _______

ALBERTA ENERGY AND UTILITIES BOARD

Table 1. Comparison of wellbore parameters and allocation calculation, Application No. 1360900

Well		Net Pay (m)			Porosity (fraction)			Water Saturation (fraction)			Validated area (hectares) (Section 88-12 W5M)			Allocation* EUB values (%)
		Celtic	Tempest	EUB	Celtic	Tempest	EUB	Celtic	Tempest	EUB	Celtic	Tempest	EUB	
2/9-10	Detrital	-	1.0	0.8	-	0.16	0.16	-	0.40	0.40	-	777, Sec 10, 11, 12	-	
	Carbonate	-	4.0	4.2	-	0.13	0.08	-	0.55	0.55	-	259, Sec 10	-	
	Total	3.0	5.0	5.0	0.135			0.25			256, Sec 10	-	518 Sec 10,11	23
2-14	Detrital	-	0.0	0.0	-	-	-	-	-	-	-	-	-	
	Carbonate	-	7.0	6.2	-	-	0.11	-	0.55	0.55	-	777, Sec 11, 12, 14	-	
	Total	4.5	7.0	6.2	0.080			0.25			256 Sec 14	-	194.25, 75% of Sec 14	12
14-15	Detrital	-	0.5	0.5	-	0.16	0.12	-	0.40	0.40	-	777, Sec 14, 15,16	-	
	Carbonate	-	7.5	7.0	-		0.10	-	0.55	0.55		518, Sec 15, 16	-	
	Total	7.0	8.0	7.5	0.095			0.25			256 Sec 15	-	259 Sec 15	18
2-22	Detrital	-	1.0	0.5	-	0.26	0.18	-	0.40	0.40	-	259, Sec 22	-	
	Carbonate	-	7.0	6.5	-	0.18	0.12	-	0.55	0.55	-	518, Sec 21,22	-	
	Total	7.0	8.0	7.0	0.160			2.25			256 Sec 22	-	259 Sec 22	21
4-23	Detrital	-	1.0	1.0	-	0.18	0.18	-	0.40	0.40	-	Not specified	-	
	Carbonate	-	0.0	3.8	-	-	0.09	-	-	0.55	-	-	-	
	Total	6.0	1.0	4.8	0.100			0.25			256 Sec 23	-	64.75, 25% of Sec 23	3
3-26	Detrital	-	3.5	3.0	-	-	0.17	-	0.40	0.40	-	259, Sec 26	-	
	Carbonate	-	0.0	0.0	-	-		-	-	0.55	-	-	-	
	Total	3.0	3.5	3.0	0.090			0.25			256 Sec 26	-	129.5, 50% of Sec 26	6
5-27	Detrital	-	2.0	1.5	-	0.30+	0.18	-	0.40	0.40	-	518, Sec 21, 27	-	
	Carbonate	-	7.0	5.0	-	-	0.09	-	0.55	0.55	-	777, Sec 26, 27, 28	-	
	Total	5.0	9.0	6.5	0.115			0.25			256 Sec 27		259 Sec 27	17

*Calculated allocation is based on the following formula:
% of pool production for well = net pay x porosity x validated area for well / sum of (net pay x porosity x validated area) for all wells x 100

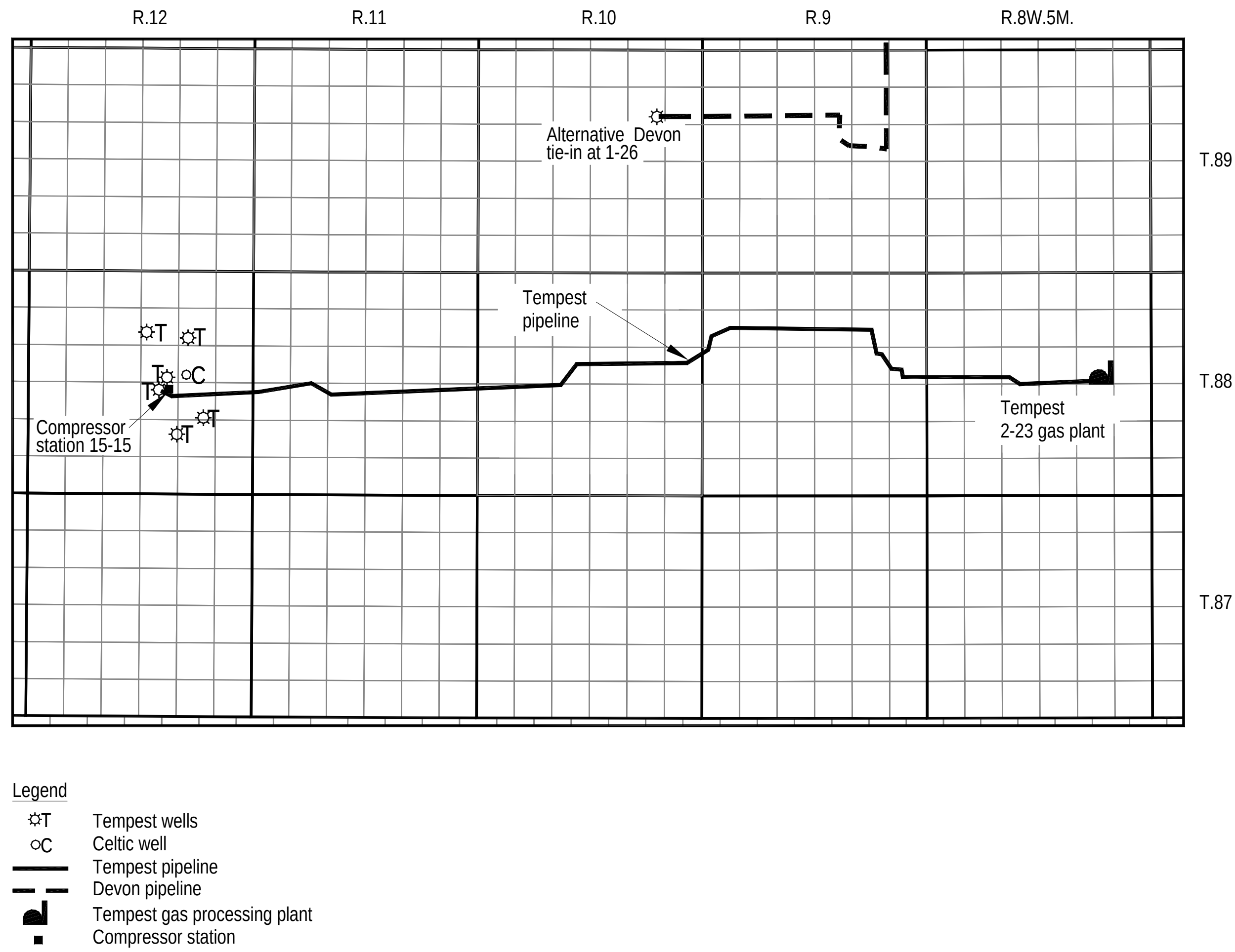
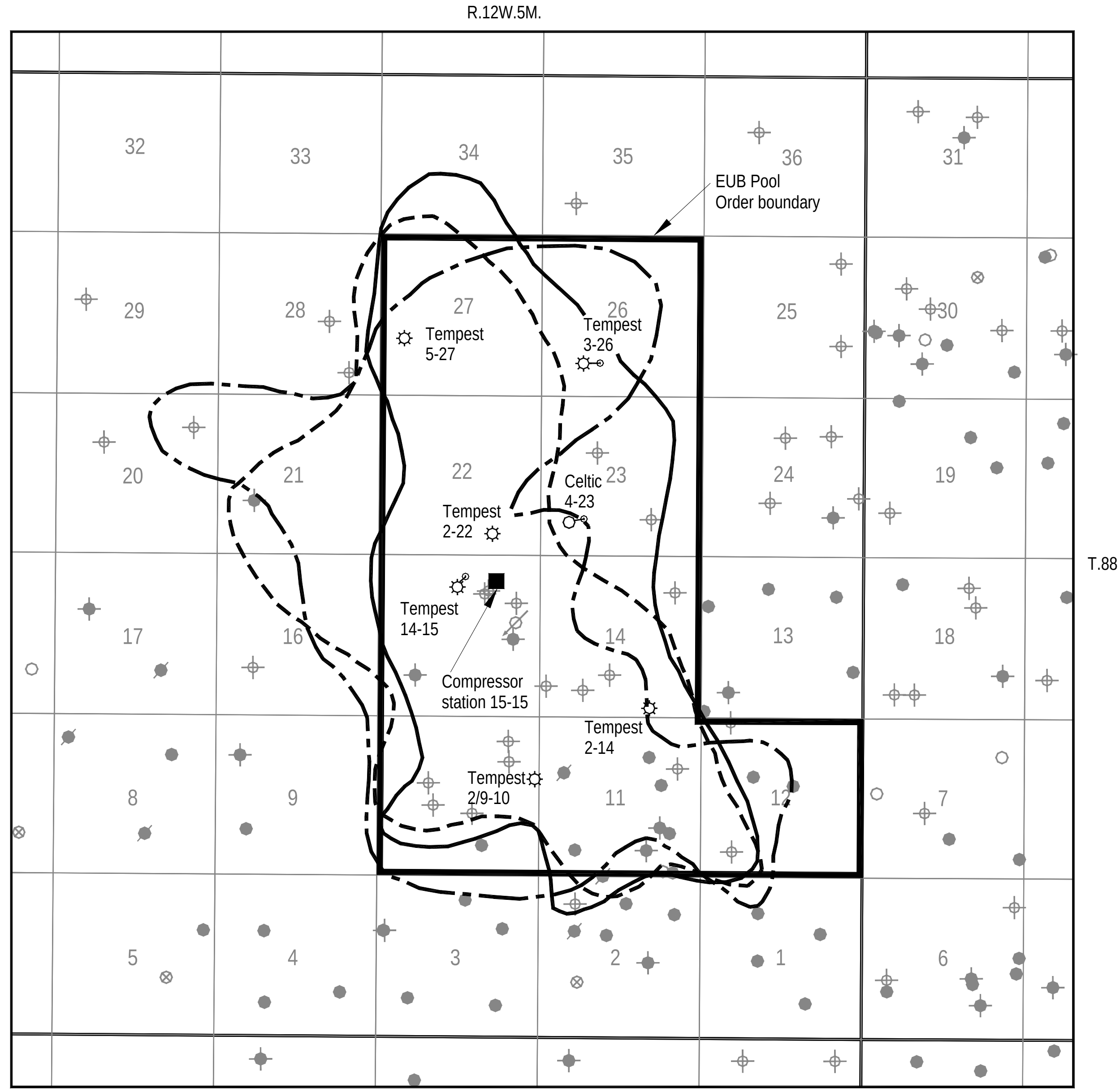


Figure 1. Overview of facilities involved in Application No. 1360900, Otter Field



Legend

- Celtic pool outline interpretation
- Tempest Banff Detrital interpretation
- Tempest Banff Carbonate net pay
- EUB Pool Order boundary
- Compressor station

Well symbols

- Oil well
- Gas well
- Abandoned oil well
- Drilled and cased well
- Abandoned well
- Injection well
- Disposal well

Figure 2. Interpretations of the pool involved in Application No. 1360900, Otter Field