SUBMISSION TO THE ROYALTY REVIEW PANEL

PRODUCTION, COST, AND ROYALTY CONSIDERATIONS
MANNVILLE COALBED METHANE PROJECTS

JUNE 22, 2007

Murray Rodgers, President and CEO
Kevin Heffernan, Government and Regulatory Affairs
Trident Exploration Corp.

1. BACKGROUND

On May 24, 2007, in Calgary, Trident Exploration Corp.'s comments and concerns with respect to the appropriateness of Alberta's royalty regime for development of unconventional gas, and in particular for wet Mannville coalbed methane (CBM), were presented to the Royalty Review Panel. Comments were based on Trident's experiences during the past several years with development of the Corbett project – the only commercial wet Mannville CBM project in Alberta (or Canada). Similarities of investment and cash flow profiles to those for oil sands developments were identified along with considerations of development lead time and uncertainties.

This written submission addresses two lines of questioning by panel members following the presentation:

- Changes in capital cost per unit of production for different drilling technology
- Our perspective on the suitability of government Research and Development programs for projects like Trident's Corbett project

It is our hope this discussion of these two issues will help the panel understand some of the cost and lead time challenges faced by resource companies in developing unconventional gas resources, and wet Mannville CBM in particular.

2. CONSTRAINTS AND LIMITATIONS OF COST ANALYSIS

The Corbett Project is a joint venture development undertaken with Nexen Inc., and Trident is not able to independently release actual costs, creating a challenge in conveying quantified information relative to cost per unit of production. The approach used for the assessment discussed in this document is to consider drilling and completion capital costs per unit of production for wells in the initial pilot at Corbett relative to costs for drilling practices and technology applied in subsequent phases.

Specific limitations of the analysis include:

- Only capital costs for drilling, completion/well stimulation and equipping operations undertaken by Trident as operator are included in the assessment. This includes about two-thirds of the development and 90% of the production to date at Corbett.
- The assessment does not consider costs for pipelines, roads, shared facilities (like gas plants, salt water disposal wells, and compressor stations), power supply, office, etc. There are, of course, significant benefits in terms of cost savings which accrue as a result of centralizing drilling activities on multi-well or multi-lateral well pads. For the Corbett Project these benefits are important, but modest in comparison to the benefits achieved through evolving drilling technology, and do not alter the conclusions presented in the following pages.

- The assessment does not consider operating costs.
- Average production rates are based on days on production for each well. As such, from an annual perspective they overstate production to varying degrees since all Mannville CBM wells have some time when they are not producing – a direct result of the significant operating challenges faced by the project.

In addition, the assessment is based on average daily production rates. The nature of wet coal seams is that production performance changes as reservoir depressurization occurs, and as a result our assessment is necessarily based on different time periods for different drilling techniques. The best approach would probably be to consider cost per unit of recoverable resource; however, with no reasonable analogy available, that is not practical.

3. COST AND PRODUCTION PERFORMANCE ASSESSMENT

Developing a commercial Mannville CBM project at Corbett required achieving excellent production behavior and dramatic cost reductions relative to the performance of the initial pilot. As indicated in the following tables, significant improvements were made in both areas but those improvements required patience, sustained investment, and a willingness to undertake very expensive experimentation with drilling, well completion and stimulation, and operating practices. The only way to test theories or proposed methods to achieve improvement is to drill, complete, and produce wells. There is no bench scale test for this type of project.

3.1 Production Rates and Royalties by Well Type

Table 1 provides a summary of average daily production rates and corresponding royalty rates for each well type. The benefits of patience and investment of risk capital are apparent. During the vertical well pilot expansions evolution of different drilling and well stimulation techniques provided only modest gains. The initial stand-alone horizontal wells resulted in a dramatic improvement in initial production rates, and refinements in subsequent horizontal wells provided further improvements. At this stage the project was on the cusp of commerciality. The development and application of multi-lateral drilling practices along with continuing refinements to horizontal drilling operations brought further cost reductions.

In this assessment "daily rate" is based on operating days. It should not be presumed that operation of all wells has been sustained since 2002. During the years leading up to commerciality almost all wells experienced significant down time as a result of equipment malfunctions or coal seam reservoir characteristics. Down time continues to be an operating challenge.

Initial evaluation wells drilled and tested during 2001 are not included in this assessment.

TABLE 1
AVERAGE PRODUCTION AND ROYALTY RATES
FOR DIFFERENT WELL TYPES

Well Type	**Average Daily Rate Per Well (mcf/d)**						
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**To date**
Vertical (Initial Pilot)	11	15	19	31	24		20
Approx. Royalty Rate	*6%*	*6%*	*6%*	*7%*	*7%*	--	*7%*
Vertical (Pilot Expansions)	7	71	34	57	41	61	52
Approx. Royalty Rate	*6%*	*11%*	*8%*	*9%*	*8%*	*10%*	*9%*
Horizontal (Stand-Alone)			147	363	347	244	308
Approx. Royalty Rate			*16%*	*26%*	*26%*	*21%*	*24%*
Horizontal (Multi-lateral)				537	833	1103	874
Approx. Royalty Rate				*30%*	*30%*	*30%*	*30%*

Multi-lateral wells are being used to commercially develop the Corbett Project. One multi-lateral well is developed on a section of land, with three horizontal wells drilled laterally from a single vertical well. For royalty purposes each multi-lateral well (with three horizontal laterals) is treated as a single well with consequently much higher royalties. For comparison, in the horizontal stand-alone case three horizontal laterals, each drilled from its own vertical well would be used for the development of a section of land. Each of those three laterals is treated separately for royalty purposes, and each qualifies for the low productivity well royalty regime. The wellbore exposure to the reservoir (coal seam) is identical for both the stand-alone horizontal and multi-lateral drilling approaches. If each multi-lateral well was considered to represent production from three horizontal wells the corresponding average royalty rate for multi-laterals for 2005, 2006, and 2007 (to date) would be 18%, 23%, and 26% rather than 30%, and the aggregate average to date would be 23%.

As a result, in a volatile commodity price environment with small operator margins combined with significant technical challenges, the 7% royalty rate difference can influence investment decisions.

3.2 Drilling Costs by Well Type

Table 2 provides a comparison of the cost per section to undertake the necessary drilling, completion, and equipping work to develop a section of land using the different drilling approaches. The vertical well initial pilot and subsequent pilot expansions are based on a four well per section development plan. The stand-alone horizontal development is based on three horizontal wells per section, and the multi-lateral development plan is based on a single vertical well with three horizontal laterals per section.

The costs for common or shared facilities, gathering, water disposal wells, power, roads, etc. are not considered in this assessment. Although the multi-lateral approach results in huge reductions in surface impacts, variations in shared facilities, access, and infrastructure costs are small in comparison to changes in drilling, completing, and equipping costs. In fact, there is no difference in cost of shared facilities and access between stand-alone horizontal and multi-lateral development.

Because of constraints on releasing specific costs this assessment provides a comparison of relative costs, based on the single section development initial pilot (four wells) having a value of 1 (one). In other words, in Table 2 below the cost to drill, complete and equip for exploitation of a single section of land using multi-laterals is 72% of the cost of using a vertical well approach identical that used in the initial Corbett project.

TABLE 2
COMPARISON OF DRILLING, COMPLETION, AND EQUIPPING COSTS FOR DIFFERENT WELL TYPES

Well Type	Cost Factor
Vertical (Initial Pilot)	1.00
Vertical (Pilot Expansions)	0.78
Horizontal (Stand-Alone)	0.96
Horizontal (Multi-lateral)	0.72

Note that a about a 25% reduction in costs was achieved by moving from stand-alone horizontal wells to multi-lateral wells. This was accompanied by a 20% increase in royalty rate (from 24% to 30% in Table 1, based on production to date).

3.3 Unit Costs by Well Type

With continually changing production rates, both through time and in terms of initial production rate, it is difficult to speak in terms of unit costs. It is particularly challenging within a context of cost confidentiality. In addition, from a production history perspective, data is very limited. Table 3 provides a way of considering the benefits gained by investing in the development of technology and its application to the resource. Because the ultimately recoverable resource (which is unknown and cannot yet be modeled with confidence) is not addressed, conclusions are probably best considered directional or indicative.

We still believe the best way to frame the advantages gained is to consider the evolution of the technology and operating procedures as leading to the cusp of commerciality with stand alone horizontal wells, and to commerciality with multi-laterals.

The assessment in Table 3 is based on the average production rate per section (four vertical wells, or three stand alone horizontal wells, or one multi-lateral well). Consideration on a per section basis allows appropriate comparison of multi-lateral wells with other well types. As in Table 2, the assessment provides relative costs, in terms of cost units per average daily rate unit (mcf/d). The base production rate used for the table is the average daily production rate for the first year of operation of wells of the indicated type. The rate differs from the calendar average (in Table 1) because gas production at Corbett has demonstrated a tendency to increase for a period of time as the coal seam reservoir is depressurized through water production, and because the rate used represents the 'per section rate'.

TABLE 3
RELATIVE COST PER UNIT OF AVERAGE DAILY RATE
(Per Section)

Well Type	Cost Factor	Average daily production per section (first year)	Cost factor units per mcf (x 1000)
Vertical (Initial Pilot)	1.00	48	20.8
Vertical (Pilot Expansions)	0.78	128	6.1
Horizontal (Stand-Alone)	0.96	987	1.0
Horizontal (Multi-lateral)	0.72	1042	0.7

Considering the available historical data the average daily production rate for stand-alone horizontal wells and multi-laterals should be considered the same. The rather modest improvement achieved by multi-lateral wells is virtually entirely attributable to cost reductions achieved through ingenuity, not by improved reservoir performance. As such, the increase in royalty rate for multi-lateral wells penalizes the ingenuity needed to create a commercial project.

4. A PERSPECTIVE ON GOVERNMENT R&D PROGRAMS

A number of federal and Alberta programs are available to provide targeted assistance for research and development within specific industry sectors (oil and gas, biofuels, agriculture, environment, etc.). Trident does, from time to time, participate in these programs for very specific and well defined research efforts, and we will continue to consider participation opportunities on an ongoing basis. Our observations and concerns about these programs generally relate to costs, timing, scale, and the business risk created through disclosure requirements. The following discussion may serve to illustrate the concerns or dilemma faced by operators when considering participation in R&D program.

Wet Mannville CBM developments will only be successful if the coal seam reservoir can be depressurized, requiring production of salt water to reduce the pressure. This is a critical success area for development of commercial Mannville CBM operations: Any operator that cannot achieve success in this area will not have a commercial project.

Unlike conventional reservoirs, coal seam reservoirs are fragile, easily damaged, highly variable, and poorly understood. When operating practices are changed reservoir response times are slow. It takes a long time to determine whether depressurization is being achieved or whether changes or new techniques have had an impact.

The ability of an operator to produce meaningful quantities of salt water on a sustained basis is affected by the inherent variable characteristics of the coal seam (degree of existing fracturing, permeability, porosity, mechanical strength and other geotechnical characteristics of the coal), the well type and drilling procedures used, well stimulation practices, the pump used, and the pumping operations or procedures, among other factors.

If an operator's pumping operations are inadequate or unsuccessful, or if a pump fails the operator must then determine which of the above factors are causing the problem and what changes are appropriate. The challenge could be any combination of:

1. Pump operation is inhibited or failed because of accumulations of fine coal or other fine rock material. This problem is very common, and difficult to solve. The problem with the pumping operation could be caused by:
   - The inherent mechanical characteristics of the coal at that specific location results in flushing of naturally occurring fine coal particles into the wellbore during pumping operations.
   - The drill bit or the method, rate, or fluids used for the drilling operation, or the well stimulation/completion method damaged the coal seam for some distance away from the wellbore. This damaged part of the seam is moving into the wellbore during water production.
   - The well cleanup operation prior to starting production was inadequate or inappropriate.
   - The design of the pump is inappropriate in terms of size, robustness, or the range of conditions under which it can operate acceptably.
2. Water production performance deteriorates through time with a corresponding inability to achieve depressurization. This could be caused by:
   - Deterioration of pump performance.
   - Inadequate well stimulation/completion or well cleanup operations.
   - The final well configuration may have deviated far enough from the well plan (a function of technical risk associated with new drilling practices) that the well is not compatible with the normal operating parameters of the pump.
   - Water has been produced at too high a rate and reservoir damage has occurred.

3. The pump is too big or too small for the quantity of water the well needs to produce to ensure both depressuring and sustained operations are achieved. This is also a common problem, but can generally be addressed by changing the pump.

We tend to speak in terms of the need to develop pump technology. In reality, the need is for depressurization technology or intellectual property – the spectrum of equipment, knowledge and operating practices necessary for development of a commercial wet CBM project. The first two challenges described above are the root of the research and development necessary to move wet Mannville CBM from a future resource to a supply source.

For a wet Mannville CBM well, installing a pump costs perhaps $100,000 and takes a day or two. Determining the appropriateness of the pump and the best drilling, completion, and operating practices to use with the pump requires drilling, completing and operating wells and developing salt water handling facilities at costs of 10's or 100's of millions of dollars over months or years. Because an operator is dealing with multiple variables and unknowns which affect depressurization, multiple attempts or trials or pilots are required in order to isolate and address the challenge each variable or unknown presents. As each challenge is addressed operators then need to demonstrate repeatability of the solution. A successful solution can be applied under a variety of conditions across a relatively broad area. This is the framework within which operators must make decisions about participating in R&D programs.

Most government sponsored R&D programs include disclosure requirements for approved projects. Using the Alberta Innovative Technologies Program (AITP) as an example, the Intellectual Property Agreement (Schedule A, Items 1, 2, and 3) requires the operator to provide to the Crown "information generated before the start of the Project relating to production history, well data, facilities debottlenecking, geological data in the Project area, experimental studies, field pilot, engineering studies and any other data that may impact the Project", all data results from the project, and ultimately to prepare a report which includes all data, analyses, etc. necessary to understand the outcome of the Project. At the time of approval of the first projects under this program (mid 2005) Trident and its partners had already made investments of hundreds of millions of dollars in undertaking relevant studies, pilots, and other work for the project.

The maximum fund available for gas projects under the IATP was $48 million, with no more than $10 million available for any one project. Clearly, in this situation, any operator must consider the disclosure business risk (five years effort and hundreds of millions of dollars) against the benefit opportunity (maximum $10 million in future royalty credits). Ultimately, Trident chose not to participate. The AITP simply did not contemplate the scale of effort and challenge facing unconventional gas development. The Program was and continues to be a valuable tool for specific, discrete, well defined research requirements related to unconventional gas, but for broad, expensive, long term requirements the Program is not appropriate.

Challenges comparable to those we have faced at Corbett will need to be addressed for development of other unconventional gas resources. These resources present new technical challenges and in each case the industry is faced with an expensive, lengthy, steep learning curve.

While there is a need and a niche for government sponsored R&D or innovation programs, they cannot substitute for a well designed royalty regime. In general the R&D programs are well suited to addressing small well defined technology challenges over a relatively short time period, and less suited to large, long term, very expensive, broad technical undertakings.

5. SUMMARY

Application of persistence, ingenuity and risk capital has demonstrated that the wet Mannville CBM resource in Alberta can be brought into commercial production, at least in the Corbett area. In light of sustained declines in Alberta's conventional supply, many more projects similar to Corbett are needed to ensure that natural gas remains a significant contributor to Alberta's economy for the benefit of future generations. It has taken several years and hundreds of millions of dollars to get to today: one commercial wet Mannville CBM project.

The resource and supply potential is huge. As an industry we will learn from each project, and over decades, as was the case with oil sands, a knowledge base will be assembled by the industry allowing the current technical challenges to be routinely addressed. However, in order to make progress the right fiscal environment must be in place to encourage the massive investment necessary.

We urge the Panel to consider the following:

- As discussed in Trident's May 24, 2007 presentation to the Panel, commercial development of wet Mannville CBM, and unconventional gas resources in general, will require long lead times and result in investment and cash flow profiles with many similarities to those which existed for early oil sands ventures.
- Considering the long lead time, large up front investment in 'on the ground experimentation', significant gas price uncertainty, and small margins the current royalty treatment of multi-laterals unfairly penalizes ingenuity and has a significant detrimental affect on high technical risk resource development.
- While welcome and ultimately beneficial, R&D programs offer limited benefit within the context of long lead times and billions of dollars of investment that will be necessary to unlock unconventional gas resources.
    - Disclosure requirements create a very large business risk when considered in the context of the lead time and investment required by operators.

- Benefits are small in comparison to risk capital, particularly when considered in the context of the huge industry investment that will be required to commercialize the resource.

Although our comments have focused on wet Mannville CBM, the themes presented apply to the spectrum of unconventional gas opportunities. The industry and the Province will be faced with comparable technical challenges, risks, lead times, and cash flow issues whether considering other CBM resources, gas shales, or deep tight sands.