PETROLEUM TECHNOLOGY ALLIANCE CANADA

REPORT

Level Best

Drilling Seasonal Load Leveling Business Case

FINAL REPORT
October 2005
Calgary, Alberta

Prepared by
PTAC Petroleum Technology Alliance Canada
and Deep Blue Associates

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Gratitude is extended to the following:

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Executive Summary

The purpose of this project was to develop and present a coherent, complete and compelling argument for greater drilling seasonal load leveling in the Western Canada Sedimentary Basin (WCSB), capturing benefits relating to:

- Drilling costs
- Safety performance
- Human resources
- Rig utilization

In recent years favourable commodity pricing has prompted rapid expansion of drilling programs in the WCSB. The development of unconventional gas reserves, particularly natural gas from coal, has put a further strain on rig and crew availability. Every year, the push is on to drill more wells. Capacity has become a more significant issue. Many operators are now turning to load leveling to secure the rigs and crews they need to complete their ambitious exploration and production (E&P) programs. Not all industry participants, however, fully recognize the benefits of load leveling to their companies or to the industry as a whole. This project set out to generate a communicable "business case study and companion presentation for reducing winter drilling activity and spreading that activity out more evenly throughout the year."

Key findings of this study include:

- Drilling efficiency has improved significantly in the WCSB over the last five years. Load leveling is already extensive in the south part of the basin, but has not yet been carried out in any great measure in the north. Drilling performance is better in the south. Overall, despite the fact that the first quarter of the calendar year is the busiest time for drilling, drilling efficiency is in no way superior at this time of the year.
- There are drilling cost advantages for load leveled operations, particularly for wells with shallow to intermediate depth profiles. The cost of drilling a well in a winter-only field can be 25% to 100% higher than the cost of drilling a comparable well in a field that sees year-round activity. The key is continuity: regardless of the season, drilling programs that proceed without interruption are more efficient.
- Perhaps the largest advantage associated with using non-winter months to bring a well to production is the reduced time from spudding to production. The benefits are far in excess of extra costs that may be required to do this.
- Load leveling can save capital and associated costs by extending utilization of the existing drilling fleet. In fact, in a better leveled environment, it should be feasible to drill the same number of wells annually with 10% to 15% fewer rigs.
- Incident (accident) rates do spike during periods of high activity in the WCSB. The first quarter sees not only more incidents but incidents at a higher rate: as much as one third higher than the rates seen at other times of the year.
- Employee turnover associated with concentrating workload into one quarter of the year can be as high as 50% and load leveling has the potential to reduce this to the more manageable neighbourhood of 20%.
- Indirect benefits of load leveling to First Nations as well as northern and other remote communities in the WCSB include jobs, permanent (as opposed to transient) residency, community support, improved public infrastructure and entrepreneurial opportunities.
- B.C.'s summer drilling incentive program is working and appears to be a win-win for industry and government. Many operators treat the incentive as a bonus – the extra nudge to pursue what already looks like a good idea. A few operators may not yet see the size of the incentive as adequate make load leveling initiative worthwhile – although for these operators there appear to be additional reasons, including traditional mindset, as to why load leveling is not yet on their agenda.

- Operators are pursuing a number of innovative load leveling practices, and season-extending technologies are gradually rising to the challenge. The road mat business, in particular, is fully engaged in meeting the rising needs of industry. Other developing technologies may further encourage load leveling activities.

In summary, there is a strongly positive business case for the continuation and expansion of load leveling behaviour. We have allowed for the considerable variance that exists in the data and in our assumptions by attempting to generate ranges of benefits and by limiting our conclusions to the conservative sides of those ranges. Incremental annual benefit to industry can be summarized as follows:

Industry Benefit From Load Leveling

		Annual Benefit
Lower well costs	$	110,000,000
Advanced production	$	420,000,000
Avoided rig construction	$	45,000,000
Reduced incident rate	$	45,000,000
Reduced turnover	$	5,000,000
	$	625,000,000

The figures above can be viewed as the minimum gross values that can accrue to the drilling industry through more aggressive load leveling behaviour. They incorporate cautious assumptions of commodity prices. At the time of printing, for example, natural gas was trading at double our assumed price; if we employ the revised figure the annual benefit would climb beyond $1 billion.

Even at $1 billion, this annual benefit is modest when weighed against the annual capital expenditure in B.C., Alberta, and Saskatchewan on exploration and development activities (excluding oil sands, capital spending was $24.4 billion in 2004). The reality is, regardless, that operators opting to pursue aggressive drilling programs without seasonally leveling their drilling activities will find good equipment and safe, high-performing crews much harder to come by. Analysts' short-term expectations may currently discourage the incremental expenditures required to achieve load leveling, but the market can be a two-edged sword; we believe that investors will ultimately punish underperformance stemming from reluctance to load level.

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1. Project Background

1.1. Introduction

A 2003 study on drilling cycle optimization1 suggested that drilling and seismic costs in Western Canada are typically higher – as much as 35% more – during winter months. The study uncovered other issues: human resource challenges for the service sector; increased workplace injuries; sub-optimal equipment utilization; and higher overall finding and development (F&D) costs. This business case follows up on findings and recommendations arising from that study. Industry interest in seasonal drilling load leveling has increased over the past 18 months, but many companies are still neither fully aware of the relative costs and benefits nor cognizant of the technologies and practices that could help them take fuller advantage of load leveling.

1.2. Load Leveling Defined

Load leveling at its essence is an alternative to building additional capacity. Load leveling tools are "strategies designed to flatten out the load curve, so that the peak is lower and the capacity factor of the system is higher".2 Load leveling is a familiar term in electricity, where utilities try to flatten the daily power loads by encouraging consumers to avoid unnecessary consumption during peak hours of demand. It is said that a perfectly flexible load leveling system can improve certain utilities' effective generating capacity by as much as 40%.3

Other industrial activities do not lend themselves as easily to load leveling. There is no way, for example, to equitably allocate "harvest time" across the seasons. The prevailing logic in the oil and gas industry has been that drilling is more like farming than power. Drilling oil and gas wells, according to the patterns traditionally adhered to in the drilling programs of most operators, makes best sense between freeze-up and break-up.

In recent years, however, favourable commodity pricing has prompted aggressive expansion of drilling programs in the WCSB. The development of unconventional gas reserves, particularly natural gas from coal, has put a further strain on rig and crew availability. Every year, the push is on to drill more wells. Capacity has become a more significant issue. Many operators are now turning to load leveling simply to secure the rigs and crews they need to complete their ambitious exploration and production (E&P) programs.

1.3. Project Purpose & Intended Outcome

The purpose of this project was to develop and present a coherent, complete and compelling argument for greater drilling seasonal load leveling in the WCSB, capturing benefits relating to:

- Drilling costs
- Safety performance
- Human resources
- Rig utilization

This project was intended to generate a "business case study and companion presentation for reducing winter drilling activity and spreading that activity out more evenly throughout the year." The audiences it aimed for include industry executives, financial analysts, asset team members, and others who influence drilling program timing. Many industry observers believed we would find advantages to load leveling, but an equal number registered their opinion that there would be at least offsetting disadvantages. We took an objective and open-minded approach to the data collection and analysis.

1 Ziff Energy Group, Western Canada Drilling Cycle Optimization, www.psac.ca/initiatives/pdf/ziff-energy-drilling-optimization-report.pdf

2 Internal Energy LLC, http://www.asktheenergydoctor.com/images/X7-Capacity.doc

3 Electric Utility Load Leveling: U.S. Technology and Markets, www.mindbranch.com/products/R2-528.html

The goal of this business case was to effect changes in approaches to the drilling business and "cause a measurable favourable impact on drilling costs, safety performance, human resources, rig utilization and finding and development costs (reduced drilling costs, seismic costs, pipeline tie-in, etc.)."[4] To that end, we have sought to assess, and crystallize, the value potentially accruing to the drilling industry through load leveling. The original scope of work for this project appears in Appendix A.

1.4. Project Structure & Methodology

PTAC Petroleum Technology Alliance Canada formed a "Drilling Innovators Advisory Group," comprised of government and industry representatives, to provide oversight to this project. Deep Blue Associates Inc., with assistance from Mike Read of DeepWell Projects Inc., was chosen through a competitive process to perform the project. Project coordination was provided by Heather Traub and Eryn Rizzoli of PTAC.

Using calendar year quarters, Deep Blue and DeepWell examined publicly available data for the five-year period 2000-2004 – for drilling activity, safety, weather, environmental restrictions and other factors. Snapshots of quarter-by-quarter drilling activity during that period can be viewed in Appendix B. Then we developed a list of candidate fields – fields with a high level of activity and several operators and a good representation of well depths, which we felt would provide us with credible quarter-over-quarter comparisons.

Treating the Western Canada Sedimentary Basin (WCSB) as six discrete regions (see Figure 1), we narrowed the list to 29 fields that we believed could provide an unbiased representation of drilling costs: few unique characteristics; high drilling volume; and a variety of well depths.

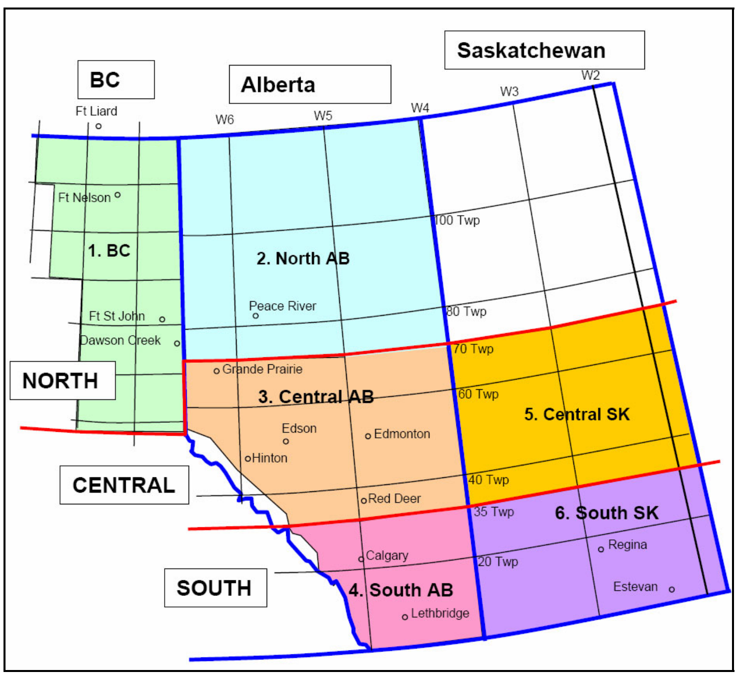

Figure 1. WCSB Regions.

We selected six additional fields in order to make observations concerning ungulate-related restrictions (west-central Alberta). Further, to collect data on wells drilled related to oil sands and heavy oil, we aggregated data from a number of wells located in northeast Alberta. Again using publicly available drilling data, we identified 14 operating companies responsible for the highest volume of drilling across our candidate fields. We approached all 14 companies with a request for

4 PTAC, www.ptac.org/drl/drlr0401.html

well cost and rig release data for the five years 2000-2004. We purposely excluded horizontal and multi-leg wells, owing to their propensity to skew results based on vertical depths.

Cooperation received from the operating companies exceeded expectations. All but one company agreed to make confidential information available to the project team. In the end, 12 operators were able to provide data in the detail required within the timeframe necessary. Many of these operators provided valuable perspective and insight in addition to hard data.

To supplement the well cost analysis portion of this project, we contacted and interviewed a variety of industry participants, including drilling contractors, load leveling technology suppliers (mats, heliportable systems, airships, etc.), and provincial agencies. While the foundation of the business case for load leveling is the hard cost data, the additional synergistic value of load leveling activities was captured by many of these qualitative probes.

Charts and graphics illustrating aspects of the story told in this business case can be viewed in Appendix C. A summary presentation package appears in Appendix D. Appendix E contains interview guides employed during the project, and Appendix F summarizes data used and sources tapped.

2. Drilling Performance Improvement

2.1. Performance Baseline

To gauge the extent to which load leveling can improve drilling, we first established a baseline by which we can meaningfully define drilling performance. Number of wells per quarter is a useful indicator at an industry level, but it does not capture one of the most significant parameters of drilling: well depth. As Figure 2 indicates, well depth can vary by thousands of metres. A “deep well” of 3,000 metres in vertical depth commonly takes 10 times longer to complete than a shallow well of 900 metres. Some rigs are capable of drilling shallow wells at a pace of nearly two per day, whereas one very deep well could take weeks to drill. Using numbers of wells drilled per given time period is insufficient for purposes of gauging drilling performance by quarter. We chose, instead, to assess drilling performance using “metres drilled per rig day.”

Well Type	Activity Parameter			Drilling Efficiency
	# of Wells	M drilled per well	Days per well	M / d
Shallow	1	900	3	300
Deep	1	3000	30	100
Relative “Activity”	1 deep well = 1 shallow well	1 deep well = 3.3 shallow wells	1 deep well = 10 shallow wells	

Figure 2. Drilling Activity Parameters.

Drilling performance changes from year to year, from quarter to quarter, and from region to region. Year-over-year performance improvements have been largely a function of improving technology. Seasonal fluctuations may relate to access, weather or rig crew experience. Regional differences are a function of geology (and therefore type of rig employed) and also of access.

2.2. Drilling Performance in Our Study Period

Figures 3 and 4 summarize drilling activity in the WCSB from 2000 through the first quarter of 2005 on two metrics: total wells drilled (well count), and metres drilled. The red lines show the trends based on annual numbers. Well count has been on a slight rise through the period, and total metres drilled has experienced a similar increase.

Western Canada

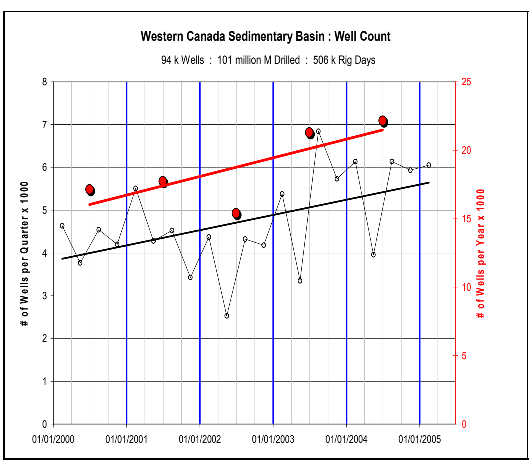

Figure 3. WCSB Well Count.
Source: Nickle’s DOB

Western Canada

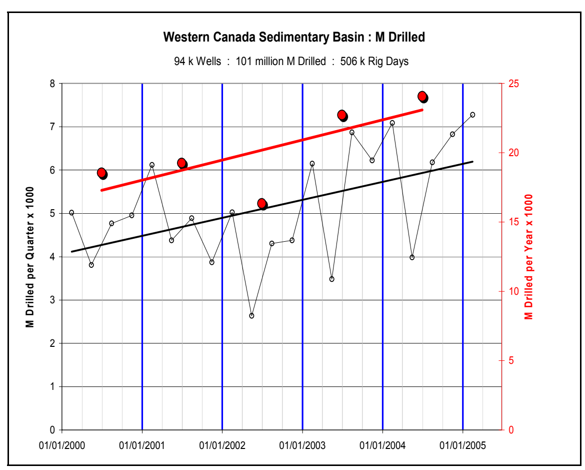

Figure 4. WCSB Metres Drilled.
Source: Nickle’s DOB

Figure 5 portrays drilling activity trends in a different light. Notwithstanding continual reports of increased activity in the patch, rig days have actually been flat through our study period. The drop in rig days relative to wells and metres drilled is associated with a significant rise in drilling efficiency (metres drilled per rig day). On the whole, we appear to be drilling holes more effectively than ever. A visual summary of drilling activity in the WCSB from 2000-2005 appears in Appendix B.

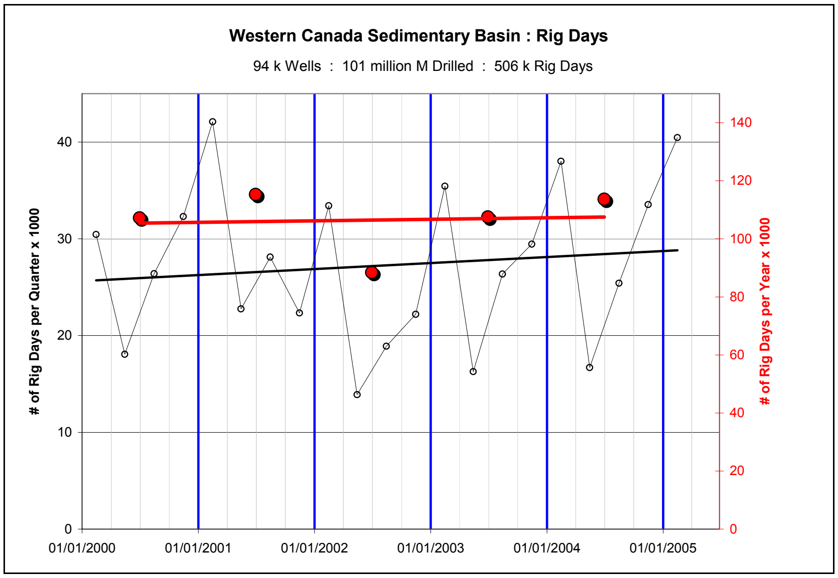

Figure 5. WCSB Rig Days.
Source: Nickle's DOB

The performance gains are particularly evident for shallow wells: over the study period, shallow well drilling efficiency has risen by almost 40%. Performance trends by well depth – shallow (less than 950 metres); medium (950-1,850 metres); and deep (beyond 1,850 metres) – are depicted below in Figure 6.

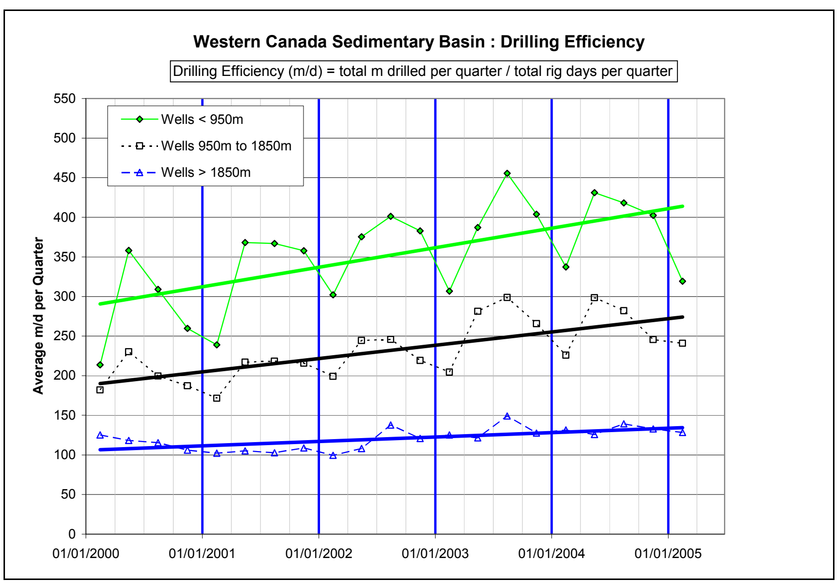

Figure 6. WCSB Drilling Efficiency Trends by Well Depth.
Source: Nickle's DOB

2.3. Drilling Performance Variations by Region

Public data suggest that although drilling performance is improving throughout the basin, it remains consistently worse in the northern portions of the WCSB. We cannot leap immediately to the conclusion that this has anything to do with load leveling; geology and access in general play big roles from region to region. Figures 7 - 9 break down regional drilling performance by well depth. The difference is most pronounced in the case of shallow wells (Figure 7), but the trend is also evident in medium wells (Figure 8) and deep wells (Figure 9). Overall, drilling performance is better, and may even be improving faster, in the south than the north.

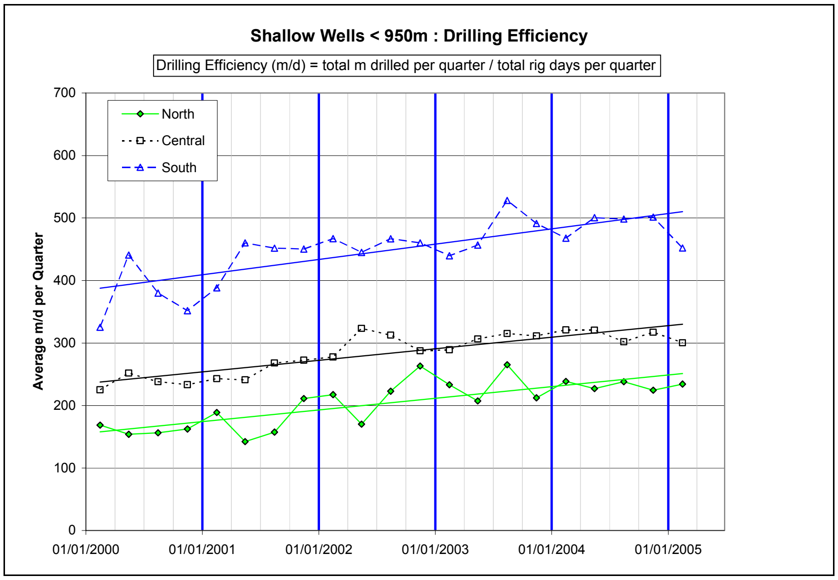

Figure 7. WCSB Drilling Efficiency of Shallow Wells.
Source: Nickle's DOB

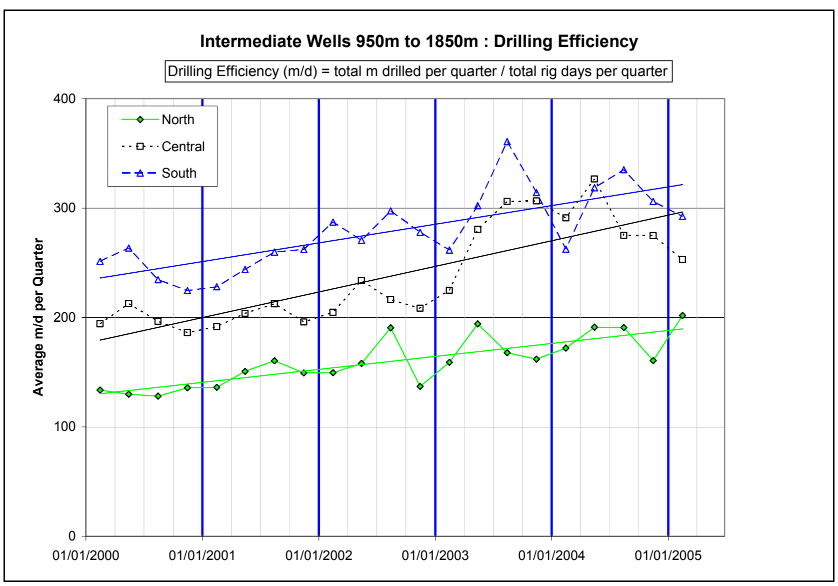

Figure 8. WCSB Drilling Efficiency of Intermediate Wells.
Source: Nickle's DOB

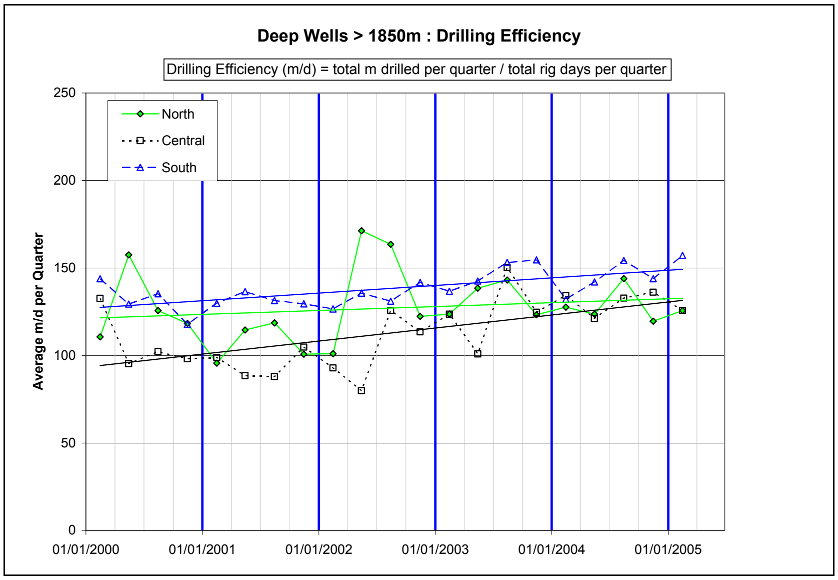

Figure 9. WCSB Drilling Efficiency of Deep Wells.
Source: Nickle's DOB

2.4. Drilling Performance Variations by Season

Figure 10 depicts the seasonality of drilling activity in the WCSB, as measured in rig days, during the study period. Drilling activity in southern Alberta and Saskatchewan (blue line) actually peaks in the summer months. In central Alberta and central Saskatchewan (black dotted line), activity peaks appear to occur most frequently in the first quarter. In northern Alberta and B.C., first quarter activity spikes typify an absence of load leveling (green line).

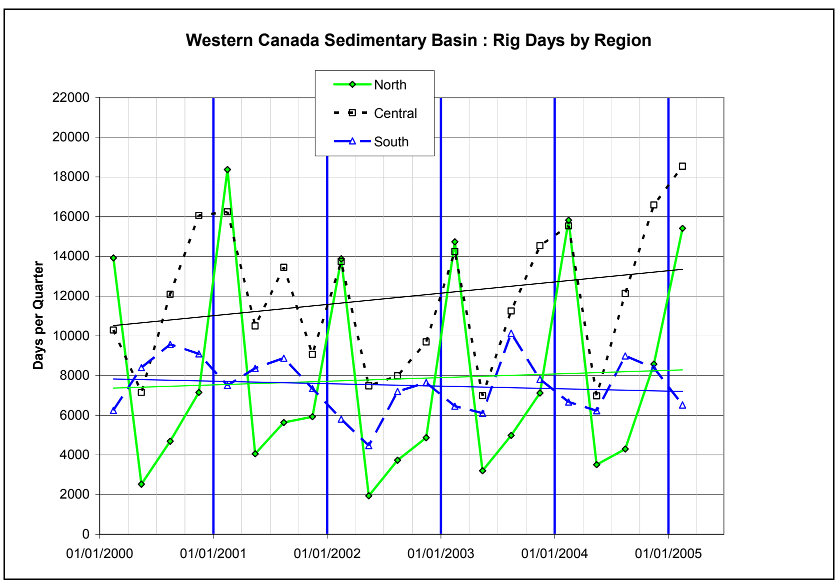

Figure 10. WCSB Rig Days by Region.
Source: Nickle's DOB

The first-quarter activity spikes in the north appear to occur across all well depth profiles, as can be seen in Figure 11.

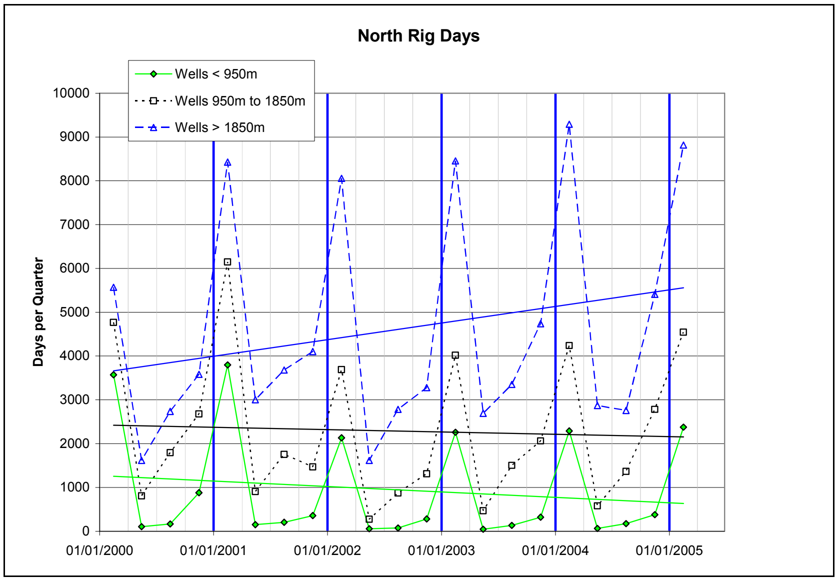

Figure 11. WCSB Rig Days – North.
Source: Nickle's DOB

Are these activity spikes accentuated on one side of the border? The answer varies by well depth. For shallow wells, the spikes occur in both B.C. and Alberta (actual rig days expended on shallow wells in northern B.C. through this period are negligible). Figure 12 shows B.C. activity (blue line) and Alberta activity (dotted green line). Due to the small number of wells drilled, a drilling performance comparison at these shallow depths is not meaningful.

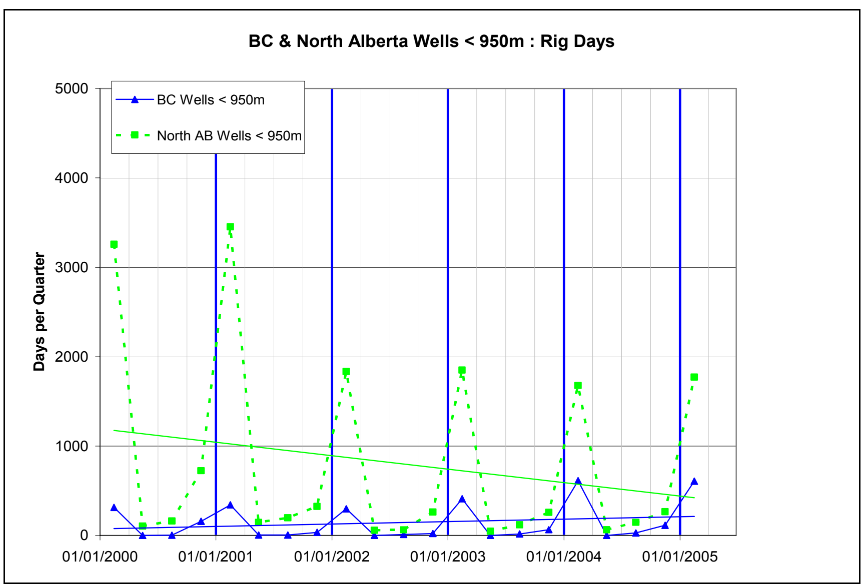

Figure 12. WCSB Rig Days – B.C. & Northern Alberta Shallow Wells.
Source: Nickle's DOB

For mid-depth wells in the north, the spikes are again evident in both B.C. and Alberta. Divergence between the provinces shows up in terms of drilling performance: Alberta has shown a trend of improving performance during the study period (a 65% rise from 2000), whereas B.C.

has shown little or no improvement. Figures 13 and 14 illustrate mid-depth well findings, in terms of rig days and drilling efficiency:

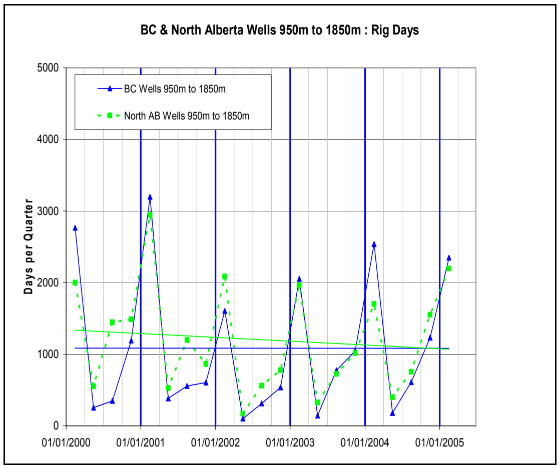

Figure 13. WCSB Rig Days – B.C. & Northern Alberta NorthernIntermediate Wells.
Source: Nickle's DOB

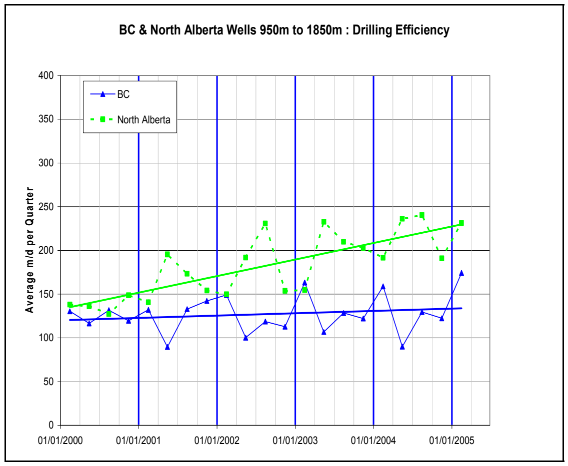

Figure 14. WCSB Drilling Efficiency – B.C. & Alberta Intermediate Wells.
Source: Nickle's DOB

For deep wells in the north, spikes are accentuated on the western side of the provincial boundary. Alberta has an appreciable (almost double) performance edge in deep well drilling through the study period, although the gap may recently have begun to close. At the deep well depth, there is clearly a correlation between seasonal load leveling and drilling performance; the question remains whether one causes the other. Figures 15 and 16 illustrate the deep well findings:

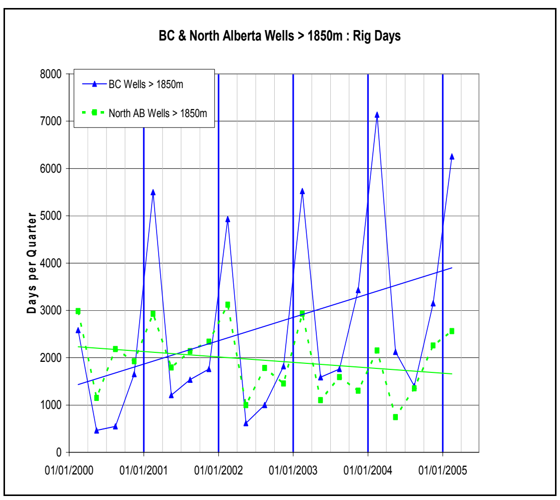

Figure 15. WCSB Rig Days – B.C. & Northern Alberta Deep Wells.
Source: Nickle's DOB

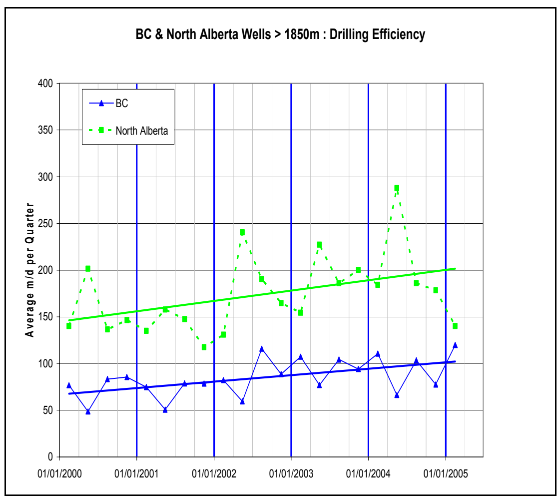

Figure 16. WCSB Drilling Efficiency – B.C. & Northern Alberta Deep Wells.
Source: Nickle's DOB

Drilling activity and drilling performance in B.C. are examined in greater detail in Section 6.1.1, which describes B.C.'s introduction of road building and summer drilling incentives.

3. Financial Impacts of Load Leveling

3.1. Impact on Well Drilling Cost

3.1.1. Performance Compared to Cost

We know from the previous analysis of public data that drilling performance (vertical metres drilled per rig day) is by no means consistently superior in the winter months. In fact, in all but the deepest wells drilled in the basin, drilling performance is clearly better in quarters other than the first quarter. Does this "performance edge" convert to lower actual drilling cost?

For wells drilled in the southern portion of the WCSB, a commonly held view is that there are additional costs associated with winter drilling: boilers, more fuel, slower operations due to the cold, higher rig rates and other premiums on equipment and services, delays in obtaining appropriate equipment or crews, etc.

For northern wells, the industry view is that the winter season's additional costs are offset by lower "winter only" access and construction costs compared to the higher all-weather construction required for summer access. In permafrost and muskeg/wetland areas, it is believed that winter-only access can be significantly cheaper.

To confirm indications from public data that drilling costs *are* higher in the winter months, we needed to review confidential well cost data and compare actual costs from wells of like depth profiles. From these confidential data, we also sought evidence that a drilling program's overall cost is moderated by extension of the drilling campaign beyond the first quarter.

3.1.2. Key Questions

Through analysis of confidential well cost data, we aimed to address two basic questions:

1. Are well drilling costs consistently higher in the winter? If so, by how much?
   - We selected for analysis fields that experienced year-round drilling.
   - Quarterly well cost averages were reviewed on a field-by-field basis.
2. Are well drilling costs moderated by extension of the drilling campaign beyond the first quarter i.e. comparing fields with similar wells, are the costs lower in the fields with year-round activity than fields with winter-only drilling?
   - The main challenge of this analysis is finding fields with credibly "similar wells." Our working assumption was that wells of similar depths, taking the same time to drill, should be about the same complexity, and therefore should be about the same cost to drill.
   - We compared quarterly well cost averages from fields that contained these similar wells.

3.1.3. Description and Limitations of Data Received

We received excellent cooperation from operators in securing data. We collected confidential cost data for a total of 2,545 wells (1,400 shallow, 600 intermediate, 215 deep and 330 very deep) drilled from 2000 through 2004. Forty-seven percent of these wells were drilled in the first quarter; 13% in the second quarter; and 20% were drilled in each of the third and final quarters.

Figure 17 shows all the data collected and demonstrates the familiar non-linear depth relationship common to most drilling performance data. It also shows the wide variation in cost (i.e. at 2,500 metres depth, the cost of a well varies from $800,000 to almost $3 million) that challenges the veracity of any sweeping conclusions.

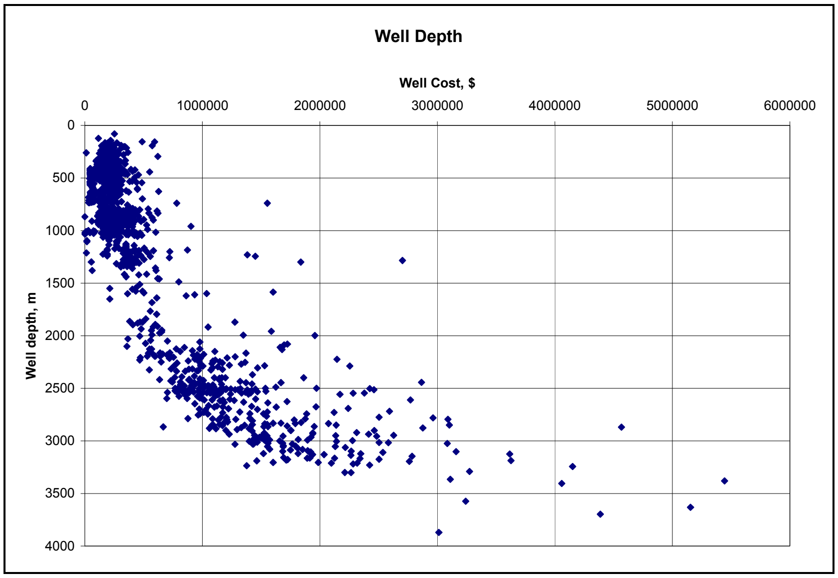

Figure 17. Data Received – Well Depth.

Once data were received by operator, we combined these data by field and generated quarterly averages for wells of similar depths in each field. We cannot present these averages by identified field because of the threat to operator confidentiality, but the masked results appear in Figure 18. For some fields there was a single "typical" well depth range; for other fields there were bimodal well depth ranges indicating distinct types of wells. In these cases, we developed two sets of "average" well parameters. The well parameters calculated included:

- Average well depth (for a well depth range)
- Average rig days (spud to rig release)
- Average total well drilling cost

Figure 18 summarizes the data obtained and shows the overall field well depth range averages. It also indicates which fields were "winter only" (B.C. and Northern Alberta). To protect data sources, the fields shown in the charts and tables are not identified by name.

Average Well Drilling Cost Data

Field	# of Wells	Ave Well Depth, m	Ave Rig Days, d	Ave Well Cost, $k	1st Q Only
AB N 2	170	272	3.0	$196	Yes
AB NE 2	7	356	2.5	$208	Yes
AB NE 4	25	375	2.0	$197	Yes
AB NE 6	16	376	3.0	$215	Yes
AB NE 5	18	412	2.4	$233	Yes
AB N 1	245	461	3.0	$233	Yes
AB NE 3	67	493	2.5	$240	Yes
AB NE 1	39	576	3.2	$232	Yes
SK S 1	167	579	1.1	$60	
AB S 1	204	641	*	$49	
AB C 1	272	835	2.1	$162	
BC 2	39	848	2.5	$372	Yes
BC 1	70	900	2.5	$343	Yes
BC 1	32	1061	3.1	$361	Yes
AB C 1	129	1125	5.3	$265	
AB C 2	5	1132	5.8	$303	
AB S 2	374	1145	*	$166	
AB WC 2	8	1174	6.2	$598	
AB NE 7	24	1220	*	$456	
AB WC 1	14	1378	6.6	$457	
AB N 3	3	1572	10.0	$866	
AB WC 3	31	2093	12.3	$681	
AB C 3	68	2152	*	$498	
BC 3	10	2154	14.5	$1,190	
AB C 2	12	2178	11.9	$601	
AB WC 2	10	2179	17.9	$1,214	
BC 4	8	2217	13.8	$1,151	
AB N 3	61	2222	*	$704	
AB C 5	13	2250	17.3	$1,298	
BC 3	8	2456	18.3	$1,225	
AB WC 3	70	2515	19.4	$1,048	
AB N 3	13	2553	17.3	$1,186	
AB WC 2	97	2717	21.3	$1,384	
BC 4	19	2827	27.2	$1,965	
AB WC 5	10	3010	30.9	$2,019	
AB WC 4	11	3013	33.2	$1,872	
AB C 4	31	3036	25.5	$1,691	
AB WC 1	23	3058	33.2	$2,013	

* = incomplete data

Figure 18. Average Well Drilling Cost Data.

A multitude of unseen factors can impact the well cost figures. Much of the cost data submitted by operators was simple “total well cost” with no detailed cost breakdown. Some data submitted were in the form of average well costs. The lack of detail and lack of apples-to-apples comparability limited our analysis in the following ways:

- Operators may have treated road and site construction and/or reclamation costs, as well as rig move (in and out) costs in different ways. We assumed, and sought to verify, that consistent cost data were reported by each operator for a specific field. We have less confidence that all operators reported their costs consistently across all fields. Thus, we have approached the field-to-field analysis with caution.
- We were not able to probe quantitatively to determine which components of well cost were higher or lower by season or by field. To overcome this data limitation, operators were asked to provide commentary.

3.1.4. Well Cost by Region

Figure 19 summarizes the average drilling costs by region. Well costs in Saskatchewan and southern Alberta (black line) are clearly lower. This is consistent with findings from the public data that highest drilling performance occurs in the south. Conversely, well costs in B.C. are the higher costs (blue line). This finding corroborates well with performance conclusions from the public data, which suggest the lowest drilling performance occurs in the north (and, in particular, in northeastern B.C.).

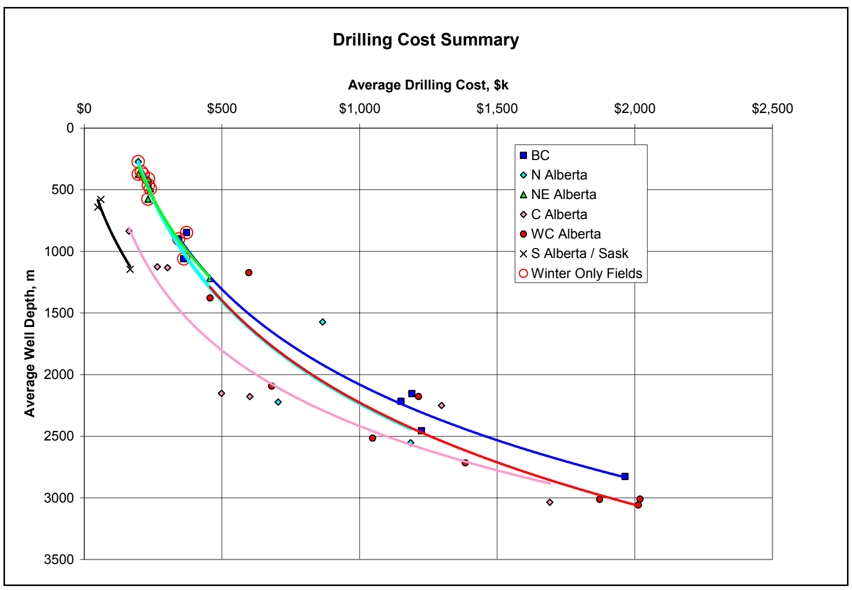

Figure 19. Summary Well Drilling Costs by Region.

Costs from the winter-only fields we selected (see data points circled, Figure 19) are consistently found along the more expensive side of the curve. We ended up with an incomplete set of winter-only field data because the deeper fields, even in the north, tend to have some all-year drilling. Cost characteristics from our winter-only fields can be seen more clearly in the following close-up graph, Figure 20. The winter-only fields are more costly than all-year fields, particularly in southern Alberta and Saskatchewan. The one high-cost load leveled field in West Central Alberta (see red circle far right, Figure 20) is more expensive because it contains a number of problem wells drilled in the near-Foothills area.

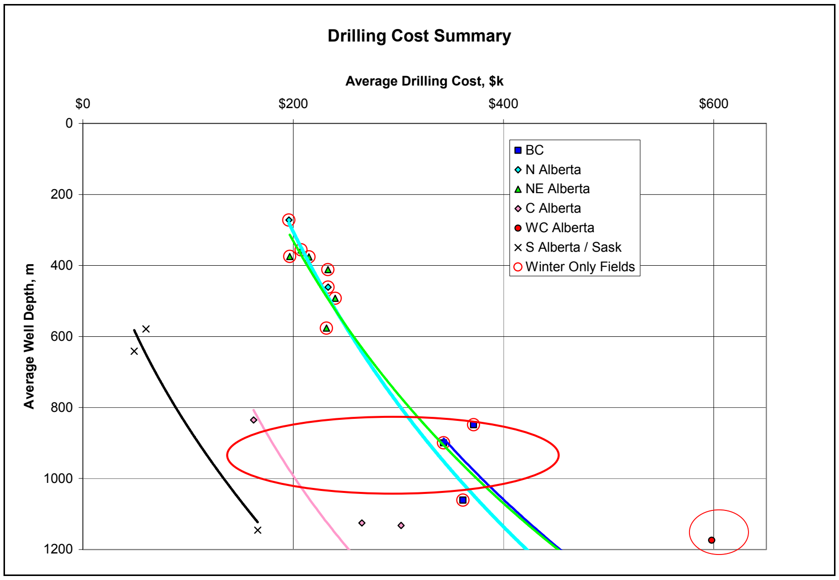

Figure 20. Summary Well Drilling Costs: Winter-only vs. Seasonally-extended.

Would the costs per well fall if the winter-only fields captured in this analysis were transitioned to load leveled (seasonally extended) activity? Certainly, the fields with fewer wells drilled over the study period delivered much higher costs per well, even when the time to drill the well (as measured in rig days) was equivalent. Infrastructure costs, even though they may be lower for first quarter work, are still a factor in the winter; if they can be spread over a greater number of wells it follows that the average well cost can decline. Contracting/service costs, often at a premium for shorter peak season work, can be negotiated downward if the term of the contract is extended. It would follow that per-well cost can and will fall should activity be increased or, even better, extended.

3.1.5. Well Cost by Activity Level

From our analysis of the confidential well cost data, it can be concluded that for high-activity, continuous drilling fields, no obvious cost differences arise between winter and summer drilling. This is likely the result of the extensive load leveling and longer term contracting and planning efforts that reduce the expected negative cost impacts of winter drilling. By seasonally extending their drilling programs, operators are succeeding in actually avoiding some of the costs that they would otherwise incur in wintertime – even though they continue to drill in the winter.

For lower activity fields that can be drilled summer or winter, there appear to be greater variances in well cost from season to season, suggesting that some of the benefits of continuous drilling are being lost. However, it cannot be concluded with any confidence that the resulting well costs are consistently higher in the winter (or higher in the summer) as a result.

For fields where activity is consistently concentrated in the winter months, the data lead us to conclude that per-well costs are between 25% and 100% higher.

3.1.6. Well Cost by Depth Profile

It is worthwhile exploring our findings by depth profile. That is, do conclusions about well cost hold steady from the shallowest of wells to the deepest?

3.1.6.1. Shallow Wells

Our dataset contained 1,400 shallow wells (under 950 metres in vertical depth) from 13 different fields. During the study period, load leveling behaviour (second and third quarter drilling activity) occurred in only three of these fields. As Figure 21 indicates, these load leveled fields demonstrated lower and generally more consistent costs (as measured in cost per metre drilled) from quarter to quarter than similar wells drilled in non-load-leveled fields. Wells drilled in winter-only fields, in fact, showed rising costs over the study period.

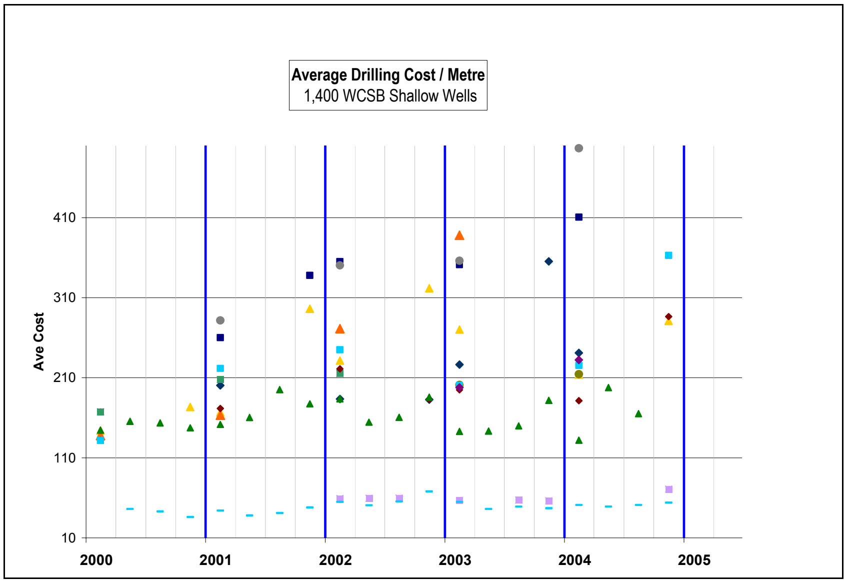

Figure 21. Average Drilling Cost/Metre – Shallow Wells.

Continuity of activity arises as one of the most significant factors at play in determining high or low cost wells. It is most evident in the winter-only fields but also in year-round fields. Figure 22, for example, shows that for a shallow, year-round high-activity field in southern Saskatchewan, there was no obvious increased cost for first quarter drilling. Higher costs did show up in the fourth quarter of 2004, and were likely associated with the break in the activity the preceding nine months.

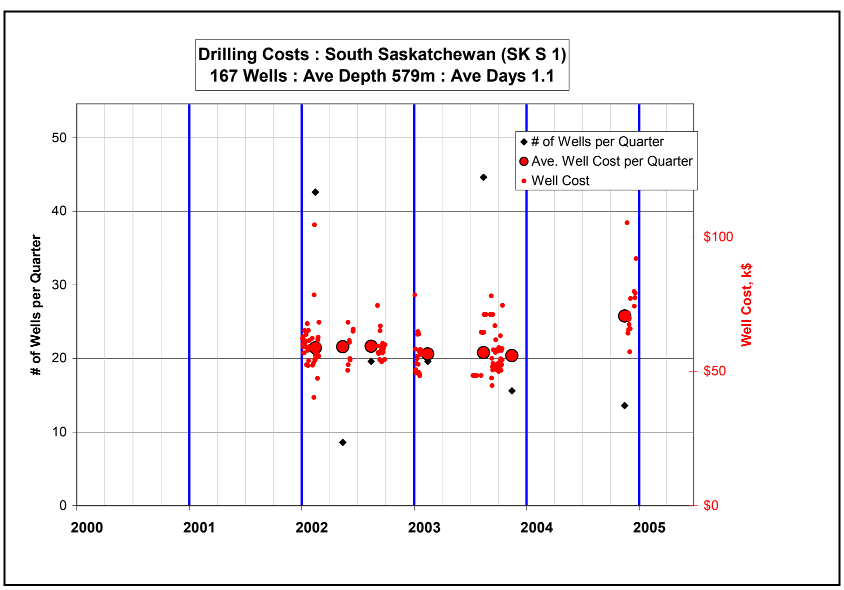

Figure 22. South Saskatchewan Year-round High Activity Field – Shallow Wells.

Figure 23 shows a very consistent finding for this depth profile: for a shallow, year-round, high-activity field in central Alberta, there was no obvious increased cost for first quarter drilling, and costs were fairly constant across the seasons.

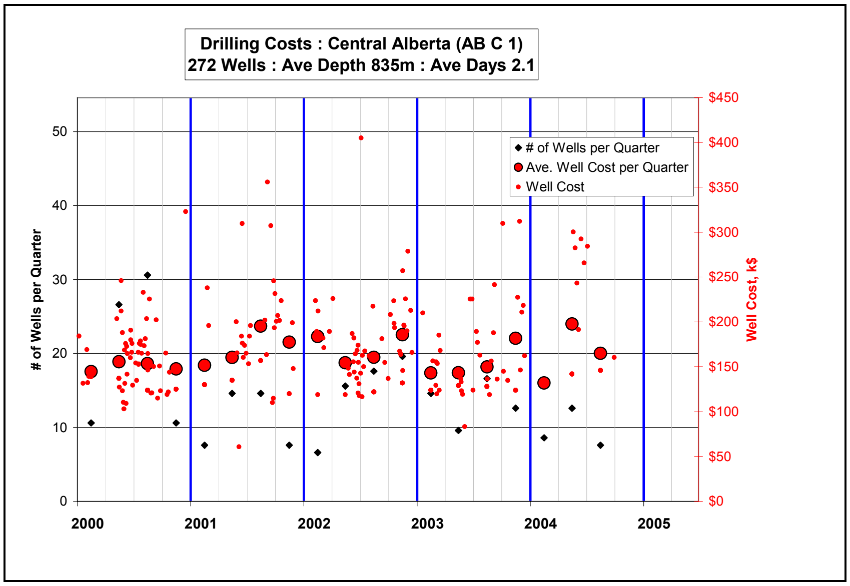

Figure 23. Central Alberta Year-round High Activity Field – Shallow Wells.

3.1.6.2. Intermediate Wells

Our dataset contained 600 intermediate-depth wells (950-1,849 metres in vertical depth) from eight different fields. During the study period, load leveling behaviour (second and third quarter drilling activity) occurred in six of these fields. As Figure 24 indicates, these load leveled fields demonstrated lower and generally more consistent costs (as measured in cost per metre drilled) from quarter to quarter than similar wells drilled in non-load-leveled fields. Wells drilled in winter-only fields, in fact, showed costs rising over the study period. These results are consistent with our findings for shallow wells.

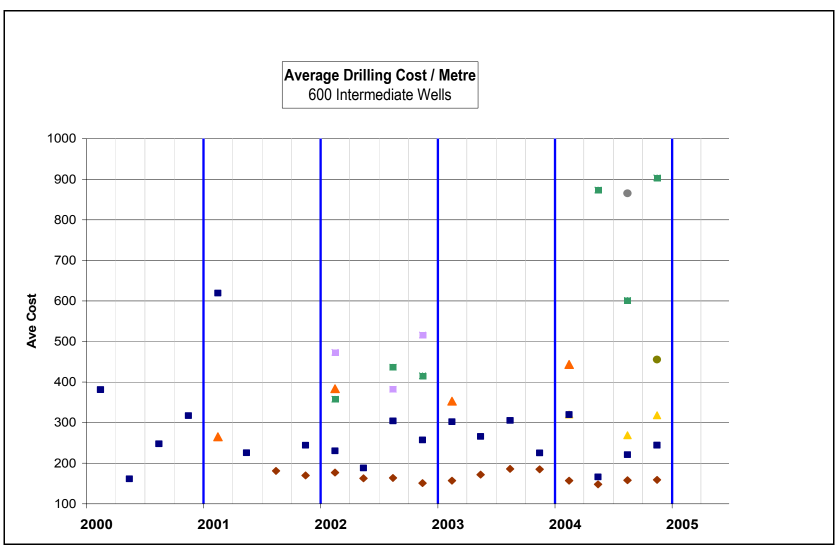

Figure 24. Average Drilling Cost/Metre – Intermediate Wells.

An intermediate depth, year-round, high-activity field in southern Alberta (see Figure 25), is typical of extended seasonal fields in that it demonstrates that in a continuous activity field, drilling costs were not consistently higher in the first quarter.

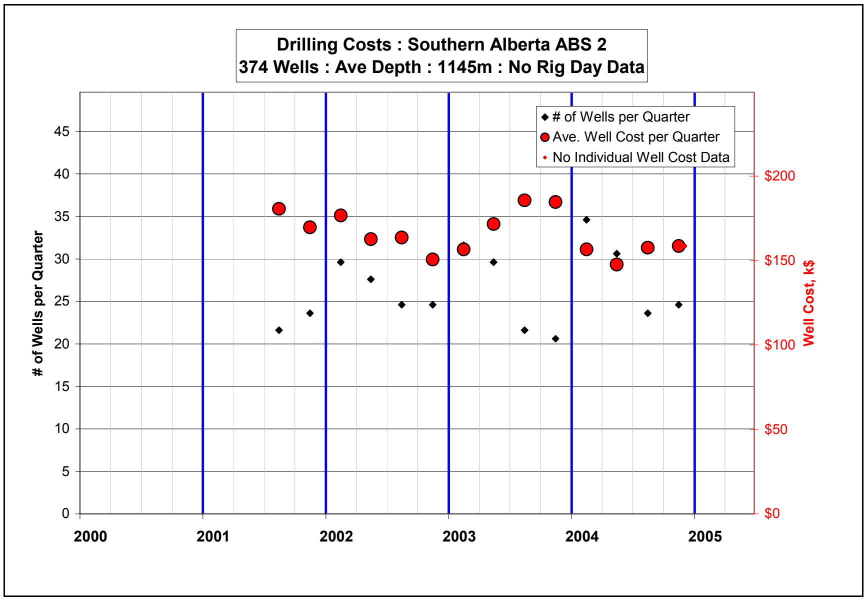

Figure 25. Southern Alberta Year-round High Activity Field – Intermediate Wells.

Figure 26 provides data from an intermediate depth, high-activity, all-year field in central Alberta. Again, there was no consistent increased cost for first quarter drilling. The high costs in 2001 are for single wells and likely indicate problem wells, not seasonal cost differences.

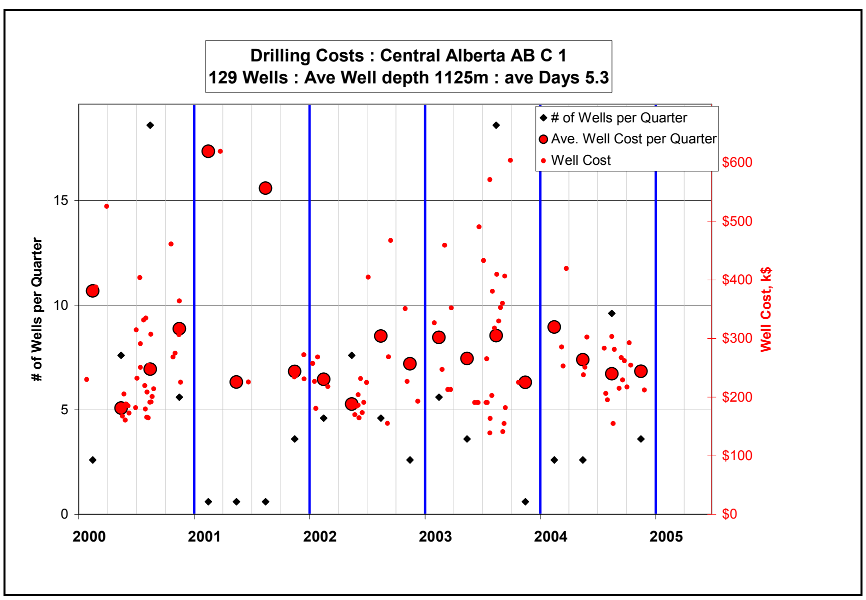

Figure 26. Central Alberta Year-round High Activity Field – Intermediate Wells.

Figure 27 shows data from an intermediate depth, year-round but lower activity field in west-central Alberta. It suggests that in fields where activity is not high or continuous, cost differences from season to season begin to emerge. In this case, average well costs are 20% to 30% lower in the third quarter. The uniformity of well costs is also greater in the third quarter.

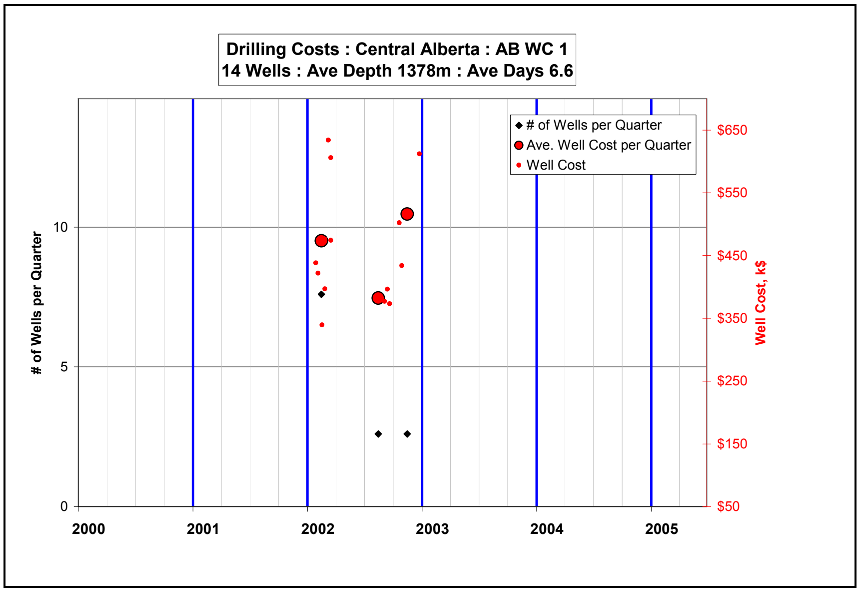

Figure 27. Central Alberta Year-round Low Activity Field – Intermediate Wells.

3.1.6.3. Deep Wells

We used data from 215 deep wells (1,850-2,399 metres in vertical depth) from eight different fields. During the study period, load leveling behaviour (second and third quarter drilling activity) occurred to greater or lesser extent in all of these fields. As Figure 28 indicates, fields in which steadier drilling occurred appeared to demonstrate lower and more consistent costs (as measured in cost per metre drilled) from quarter to quarter.

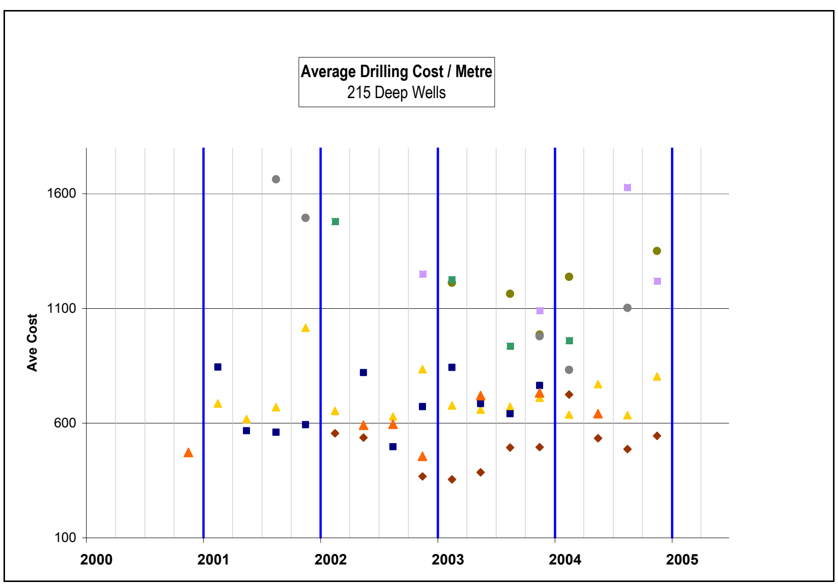

Figure 28. Average Drilling Cost/Metre – Deep Wells.

Figure 29 suggests that for a deep, all-year field with relatively low activity in west-central Alberta, average well costs appear to be 20% to 30% lower for summer wells than for winter wells.

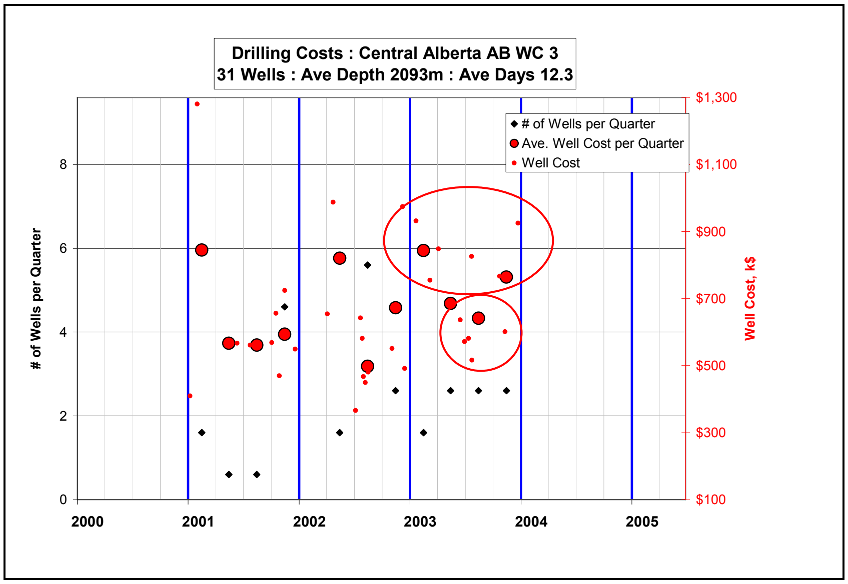

Figure 29. Central Alberta Year-round Low Activity Field – Deep Wells.

Figure 30 shows that for a deep, all-year field in central Alberta, average costs were lower for summer wells than for winter wells in 2002 and 2004. In 2003, however, winter wells were more competitive. These data are insufficient to permit the conclusion that winter well costs are consistently higher or lower in continuous activity (load leveled) fields.

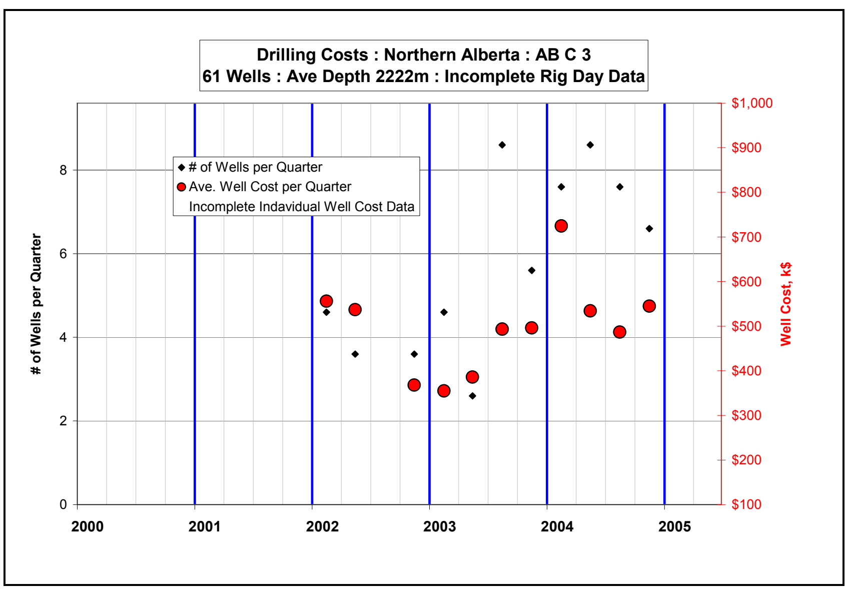

Figure 30. Central Alberta Year-round Field - Deep Wells.

3.1.6.4. Very Deep Wells

We used data from 330 “very deep” wells (2,400 metres and deeper) from 11 different fields. During the study period, load leveling behaviour (second and third quarter drilling activity) occurred to greater or lesser extent in all of these fields. Figure 31 fails to show any clear pattern in the data from these very deep wells.

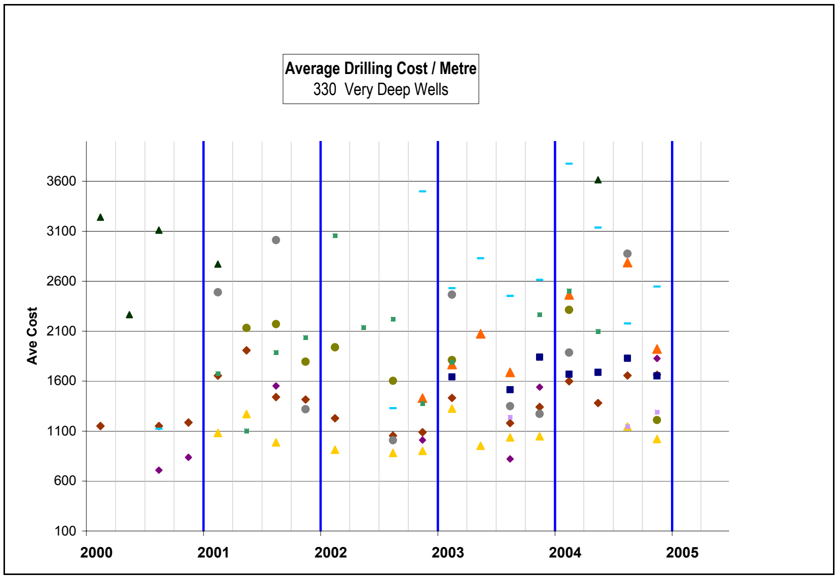

Figure 31. Average Drilling Cost/Metre - Very Deep Wells.

Figure 32 isolates data from one field in northern Alberta, where 97 very deep wells were drilled over the study period. For this particular field, which already exhibits extended season drilling activity, there was no consistent average cost difference between summer and winter wells.

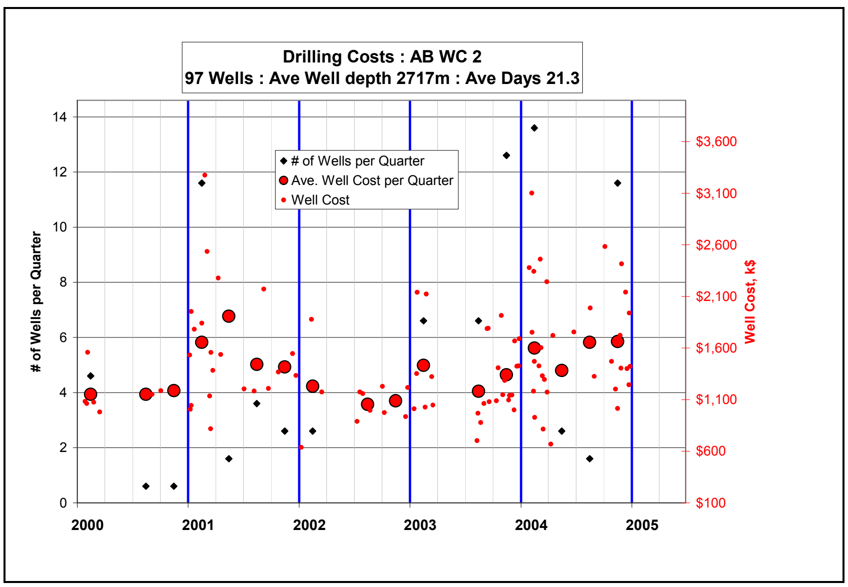

Figure 32. Northern Alberta - Very Deep Wells.

Figure 33 isolates data from a field in central Alberta, where 31 very deep wells were drilled during the study period. There was no obvious average cost difference between summer and winter wells. It cannot be suggested, for these very deep wells in fields with extended seasonal activity, that winter drilling costs are consistently higher.

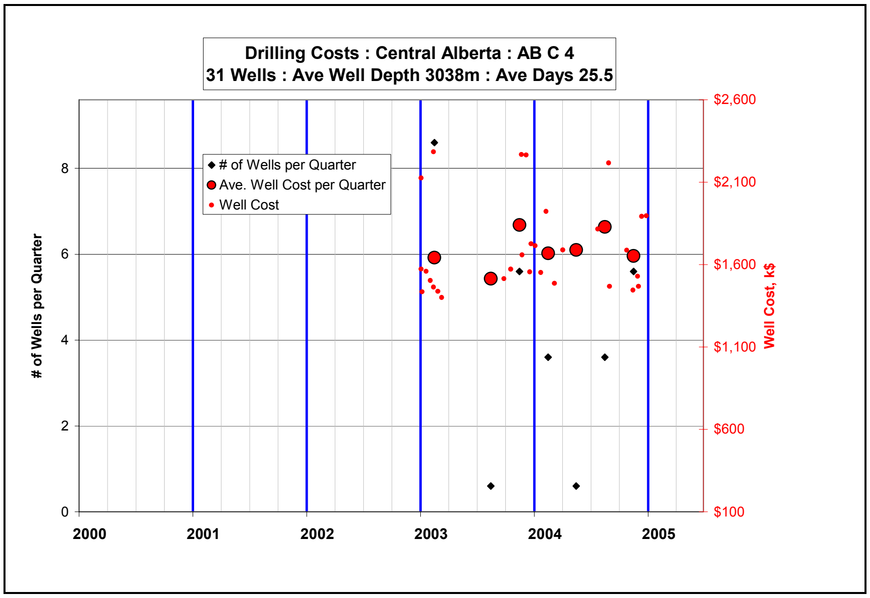

Figure 33. Central Alberta –Very Deep Wells.

Figure 34 isolates data from a very deep, all-year field in British Columbia that saw only 19 wells drilled in the study period. Even with this low level of activity, it cannot be concluded with any consistency that winter drilling costs are higher or lower than summer season drilling.

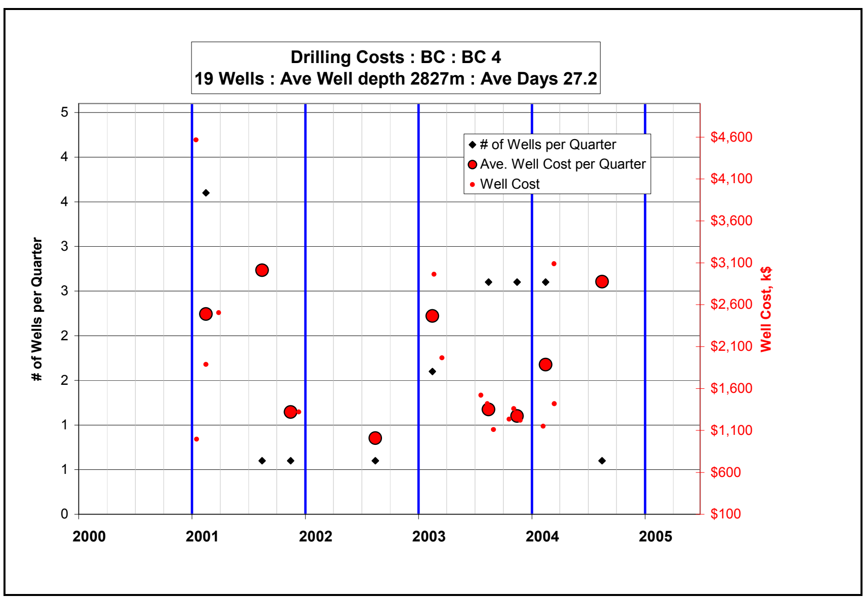

Figure 34. B.C. – Very Deep Wells.

3.1.7. Well Cost Conclusions

Well cost appears to be a function of *continuity of activity* in most fields. Where activity is limited to one season (i.e. winter-only), costs are higher – they can be double the cost of drilling in a seasonally extended, higher activity field. Where a low level of activity is extended over the seasons in a field, variances from well to well and season to season do occur but no single season is consistently the more expensive time to drill. Where a higher level of activity is sustained over at least three seasons, the cost of drilling a well – particularly of shallow or intermediate depth – appears to be not only minimized but less variable.

We have tested our findings with a variety of operators and drilling contractors, whose anecdotal evidence supports these conclusions. Two factors are consistently reported: favourable terms for extended (e.g. minimum 250-day) drilling contracts, and pace-setting performance gained from drilling crews that work together over extended periods (e.g. nine months instead of three months).

We believe that there are at least 1,500 wells currently drilled per year in the WCSB in truly winter-only environments. Pegging an average cost of a winter-only well as $750,000, and assuming that in only half of these locations would it be physically feasible to develop seasonally extended activities, we surmise that industry can potentially save in the order of $110 to $280 million in well costs (i.e. between 20% and 50% cost savings for the wells that could be more continuously drilled) by adopting seasonally extended drilling programs. In other words, on well cost savings alone, industry could justify spending at least $110 million a year to pursue seasonally extended practices in fields currently operated as winter-only drilling locations.

3.2. Impact on Time to Production

The contraction of the period of time from spudding to commercial production is probably recognized by industry as *the* most significant benefit available from load leveling. The ability to complete and tie in a well (i.e. achieve commercial production) months or even a full year ahead of schedule is “money in the bank” for operators, particularly in the current environment of high oil and gas prices. Operators today are building business cases for season extension on this factor alone.

Even if completing a well during the summer months adds hundreds of thousands of dollars to well cost (i.e. cost of all-season road construction, mat costs, etc.), the benefit of bringing a significant volume of oil or gas on-stream without delay generates a readily compelling financial argument.

For example, an operator in northeastern B.C. reported spending an additional $200,000 by using the summer months to complete a well. Because the operator chose not to wait, the well was tied in three months earlier than it would have been otherwise. The result in this particular case was that the operator was able to bring 10 million cubic feet of natural gas per day on-stream 90 days ahead of schedule.

Using gas prices that were about $7 per Mcf (thousand cubic feet) at the time of drilling, the operator achieved early realization of about $6.3 million in revenues (or probably $2.5 million in netback). Those cash flows would have been achieved anyway, but the delay is telling. Using industry norms for decline and discount rates, the net present value advantage to the operator over waiting is still in the order of $800,000 – far outpacing the incremental $200,000 expenditure necessary to complete the well early. Taken to extremes, that operator could have spent about $1 million on seasonally related costs and still come out marginally ahead.

Was it a gamble? Of course. Not all wells turn out to be as prolific. But, as was pointed out to us, in times of high commodity pricing, the risks of waiting are not necessarily any less. Risks are part of E&P, and a bird in the hand is worth two in the bush.

What does this mean on an industry level? Every year, in the northern parts of Alberta and B.C., drilling and completions activities are interrupted for periods of months. We assume average gas flow rates of new wells in these areas are in the order of 1,000 Mcf/day, with an annual decline rate of 20%. The drilling success rate over the last three years has been in excess of 90%. Projected through seasonally extended drilling and completions activities, 10% of the wells drilled annually in northern B.C. and Alberta (about 3,000 new wells a year) could be completed on average three months ahead of schedule, generating a net present value advantage of $420 million. This implies that at commodity prices that are modest by comparison to those at play currently, industry could spend several hundred million dollars a year on incremental costs associated with seasonally extending activities (i.e. all-season road construction, mats, etc.), and it would still come out ahead by invoking seasonal load leveling practices.

3.3. Impact on Rig Utilization

Load leveling offers the opportunity for industry to use its equipment for upwards of 250 days per year. Currently, some of the larger drilling contractors are prepared to offer “summer-level” rig rates year-round if a minimum 250-day commitment is made by the operator. The current reality is that many operators have to secure these season-extending contracts simply in order to obtain the use *any* rigs.

By the end of 2005, there will be an estimated 775 drilling rigs in service in the WCSB.[5] The last year that the fleet actually shrank was 1993. The replacement value of today’s fleet is in the neighbourhood of $6.5 billion.

Fleet utilization rates have traditionally been a function of commodity prices as well as weather. In 1997 a combination of advantaged weather and robust commodity prices led to a stellar overall utilization rate of 82%.[6] By contrast, market doldrums precipitated an overall 47% utilization rate in 2002. It has been much lower: in the early 1990s fleet utilization averaged less than 30%. Every April, utilization temporarily sinks to those levels as the industry waits out spring break-up. Figure 35, below, depicts this annual dip.

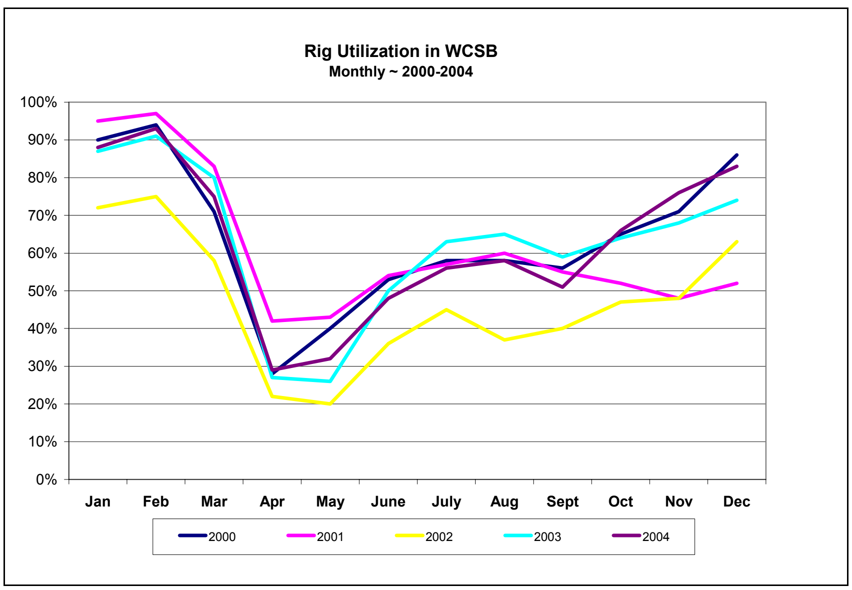

Figure 35. WCSB Rig Utilization Rates 2000-2004.
Source: CAODC

5 Some in industry are suggesting the number will be at 800. Fleet size at time of printing according to CAODC was 738.
6 Fleet utilization numbers in this section were provided by CAODC.

Load leveling is not just about squeezing more utilization from our rigs in April or May but in returning, to the extent possible, to sustained healthy rig and crew utilization levels as soon as possible following spring break-up. If more rigs were operating in October, for example, the "ramp-up" to winter drilling would not be as steep and many of the issues associated with this ramp-up would be avoided. Further, under normal industry conditions, assuming more drilling was to take place between June and November, less would have to take place between December and March. It is left to each operator to decide whether this means accelerating its drilling program (i.e. moving next-winter costs into the previous summer/fall period) or delaying it (i.e. moving the winter costs into the following summer/fall period).[7]

In 2004, the peak utilization month was February, when 93% of the fleet was active; the valley occurred in April with 29% utilization. The fleet grew throughout the year. We redrew 2004's utilization pattern assuming:

- No more than 80% of the fleet would be available at any given time
- It is possible to improve spring break-up utilization, but not by much
- Utilization could be significantly improved in the summer and fall through load leveling

Ensuring that the same number of rig days was logged in 2004 regardless of the utilization pattern, we came up with the data in Figure 36. This chart suggests that fewer rigs would be required – probably 10-15% fewer – to achieve the same number of annual rig days (thus the same number of wells drilled), if the fleet could be better used from June through November.

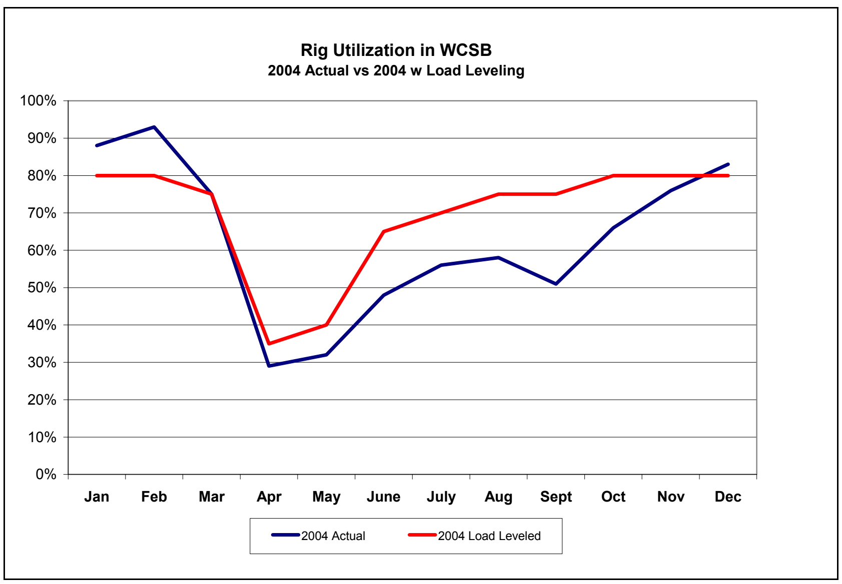

Figure 36. WCSB 2004 Rig Utilization - Actual vs. Load Leveling.

During 2004, the actual rig count in Western Canada climbed from 687 to 717, an increase of 4%. Industry spent an estimated $250 million on these additional rigs. With load leveling, the argument could be made that we could have achieved the same number of wells drilled without these new rigs and, additionally, we could have managed without having to employ 40 or 50 of the fleet's older (less efficient and more dangerous) existing rigs. The corollary is that we could have also gone without using the bottom of the barrel of the crews – typically the crews that were greenest, poorest performing and most subject to safety concerns. The conclusion is that the financing cost of 70 or 80 rigs – or about $45 million a year – could be treated as an annual potential gain of load leveling.

7 Clearly, financial advantages would be maximized by advancing the program rather then delaying it. In the prevailing environment, the decision would probably not entail reducing winter activity so much as better filling the rest of the seasons.

3.4. Impact on Safety Performance

Recognition of the cost of incidents in Canada's oil and gas industry – financial, individual, liability, societal, reputation – has been rising in recent years. The industry has made strides in safety and is more determined than ever to continue to bring incident frequencies down. Load leveling is seen as one of the tools that industry can invoke on its "journey to zero."

3.4.1. Correlation with Activity Spikes

Are incident rates correlated with drilling activity spikes? Worker compensation statistics are available for each quarter and are broken out by province (but not by region within each province). Additionally, the Canadian Association of Oilwell Drilling Contractors (CAODC) maintains industry-wide total recordable incident frequency (TRIF), published as a 12-month rolling average.

To deduce a by-quarter incident frequency, we used claim counts received from the provincial worker compensation boards (WCBs) and we estimated person-years by quarter based on the assumption that a drilling rig requires a crew of 10 over a 24-hour period. These estimates are imperfect, but they allowed us to build the following trend charts by province, showing total claim count as well as a measure for incident frequency.

3.4.2. Safety Performance in B.C.

The B.C. drilling industry experienced significant spikes in claims in the first quarter of each year in the study period (see green data points, Figure 37). Safety performance as measured in incident frequency (red data points) presents more moderate swings, but the first quarter spikes remain evident. Incident rates drop significantly through the study period, suggesting the B.C. oil and gas industry is making headway in its "journey to zero."

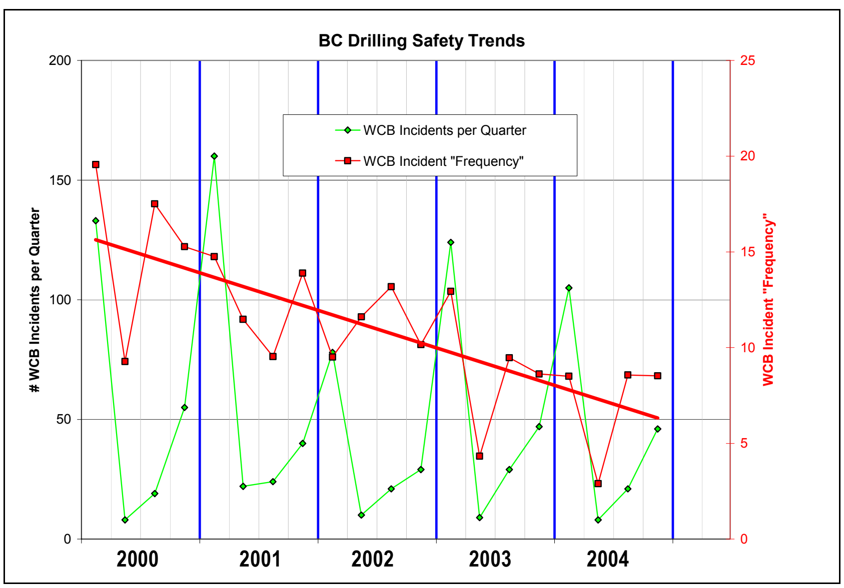

Figure 37. B.C. Drilling Safety Trends.
Source: Workers' Compensation Board B.C.

3.4.3. Safety Performance in Alberta

Alberta's drilling industry also experienced spikes in claim numbers in the first quarter of each year in the study period. When converted to an incident frequency measure to reflect safety performance, the spikes are still evident. Incident rates appear to be declining through the study period, although not at the same pace as in B.C. Alberta safety performance is shown in Figure 38.

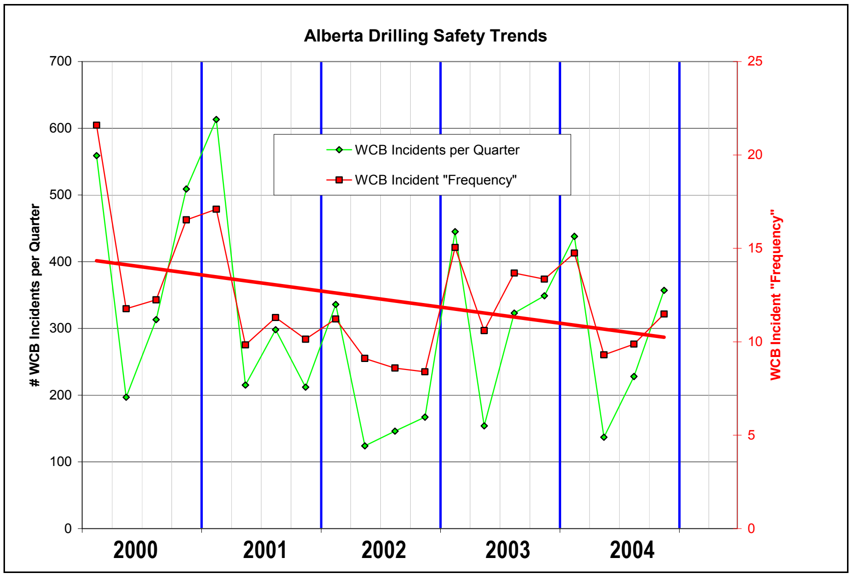

Figure 38. Alberta Drilling Safety Trends.
Source: Workers' Compensation Board Alberta

3.4.4. Safety Performance in Saskatchewan

In terms of volume of incidents, first-quarter claim spikes in the Saskatchewan drilling industry are not as accentuated as in the provinces to the west. However, over the study period, the first quarter was consistently the worst quarter in terms of safety performance (incident frequency). The overall trend in Saskatchewan, as in Alberta and B.C., is downward and can be seen in Figure 39.

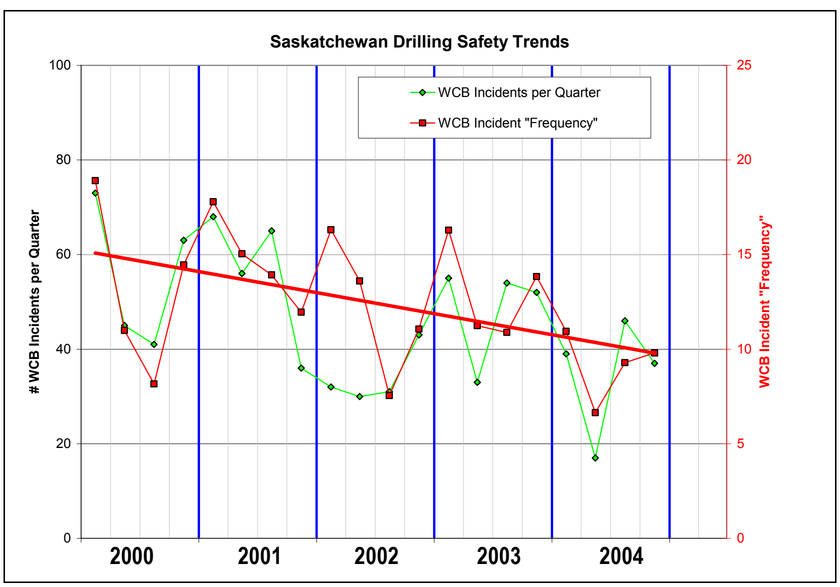

Figure 39. Saskatchewan Drilling Safety Trends.
Source: Workers' Compensation Board Saskatchewan

3.4.5. Contractor Incident Tracking

Some of the better incident tracking available is conducted by the basin's large drilling contractors. We successfully obtained recordable incident data from one company holding a meaningful share of the drilling business in each of the three provinces. This company has been successful in driving its TRIF downward in recent years, in part by working with operators to spread its work over more months of the year. Regardless, the company's own statistics continue to indicate that when it is busiest, not only its total recordable incidents but also the *frequency* of those incidents (on a per-person-hour basis) is highest. In its worst year of the last four, the company incurred 51% of its total annual recordables in the first quarter, while chalking up 37% of its total annual person-hours through the same period. Its first-quarter incident rate that year was 40% higher than the company's full-year TRIF.

Contractors and operators alike have been attacking the safety performance issue head-on in the last two years. The Drilling Safety Focus Group now meets every quarter, giving line managers the opportunity to share what is working and not working. Along with broader leadership training and improved driving, load leveling has been identified as one of the keys to lowering the drilling industry's incident rate.

3.4.6. CAODC Injury Analysis

CAODC maintains a 12-month rolling average TRIF. It shows the gains the contracting community has made in recent years. TRIF in the first quarter is generally higher than TRIF in the remaining quarters of the year, but in view of the ongoing improvement trend, it is not possible from CAODC numbers to conclude that the incident rate "spikes" in the first quarter. CAODC's statistics show that the first quarter of the year is responsible for about a third of annual fatalities.

3.4.7. Pegging a Cost to Incidents

How much does it cost industry to accommodate higher incident rates in the first quarter? A study recently completed on cost of incidents in the Canadian upstream oil and gas industry suggested that the average cost of a recordable incident (incorporating fatalities, lost-time cases and non-fatal, no-lost time incidents) was about $42,000 in 2002. One of the industry sources we spoke to estimates the cost of a recordable incident to his company as $45,000. According to the statistics we have assembled, a reduction in the incident rate in the first quarter of about one third would bring the rate more in line with the rate achieved through the rest of the year. Assuming the ratio of fatalities to lost-time incidents to recordables remains relatively consistent from season to season, the 33% drop would correspond to an industry-wide savings of about $45 million per year.

Of course, cost is only one part of the overall safety equation. The industry pays a penalty every year when it cannot attract workers who hold the perception that rig work is dangerous. And the costs of safety extend far beyond financial implications to industry – into personal, family and societal penalties incurred.

3.5. Impact on Human Resources

3.5.1. Industry Challenges

A comprehensive study published in 2003 by the Petroleum Human Resources Council of Canada (PHRCC) identified key issues facing the upstream oil and gas industry from a human resources (HR) perspective. The study highlighted the industry's seasonality as a major limitation on the industry's ability to attract and retain a skilled workforce in the WCSB. The drilling, seismic and service sectors of the industry all reported *continual* difficulty attracting and retaining skilled workers. Workers fail to see long-term career opportunities in seasonal work. This lack of qualified workers has raised sustainability and safety concerns in the industry.[8]

Another issue raised in the study is the myth that these sectors can readily draw from the "unskilled labour pool." This misguided belief can hinder the development of progressive

8 PHRCC, Strategic Human Resources Study of the Upstream Petroleum Industry: The Decade Ahead, 2004.

hiring and training programs. The reality is that more and higher skill levels are being required in order to keep pace with technological improvements and automation within the industry. Further, as operational efficiency becomes a key strategy for companies, the use of compensation to attract and retain employees becomes less sustainable.[9]

As we head into the winter of 2006, many of the foresights of the PHRCC report are coming to fruition. During 2005 some operators have been able to proceed with their drilling programs only through the use of two instead of three crews per rig. One operator reported to us that he will have "the iron" in place for his winter program but that some rigs will stand idle simply because crews will not be available to run them.

The 2003 study provided the following comment: "Optimizing the drilling cycle, reducing the seasonality of the work and providing workers with training, certification and a career ladder may address current attraction and turnover issues among skilled workers."[10]

There is no question that human resources issues have the potential to severely limit the oil and gas industry. The pace of growth for many companies in the industry is currently limited not by market demand or financial capital but by unavailability of human capital. In order to address these issues, several initiatives and programs have been put in place, largely aimed at increasing training and skill development. The industry has also attempted to increase its available labour pool by introducing programs to attract Aboriginal people into the industry. For example, the Aboriginal Drilling Rig Training Program established by Western Lakota focuses on providing training to members of several Aboriginal communities. As of spring 2005, the program had produced 39 graduates.[11]

3.5.2. Apprenticeship Program

Alberta's drilling industry is the first in the world to implement compulsory trade certification for drilling occupations. In October 2004, the provincial government designated "Rig Technician" a compulsory certification trade. The CAODC states that by establishing Rig Technician as a trade, the drilling industry will reap the following benefits:

- The establishment of a formal career path and training program for jobs that fall under the Rig Technician designation (motorhands, derrickhands and drillers).
- Communication to those within and outside the industry that rig employees are trained, and knowledgeable, tradespeople.
- An increased level of safety on the job site.[12]

Rig Technician certification is expected to improve the industry's ability to attract new employees into positions that are currently occupied by highly skilled workers. Technical work environments demand a variety of skills. As such, drilling industry employees and management have developed high quality training standards for the Apprenticeship Program. The move to this certification has answered demand by the drilling industry for a higher level of employee professionalism.[13]

In addition to the Rig Technician certification, steps are being taken to increase the level of training to service rig workers through the establishment of competency programs. The goals of the competency programs are to provide a reliable industry standard for training and to provide transparent employee competency verification which can be transferred among CAODC member companies.[14] The oilfield services industry currently has nine occupations in Oil and Gas Transportation Services and Well Testing Services recognized as Designated

9 Ibid.
10 Ibid.
11 The Canadian Oil Driller, Experience for Hire, Spring 2005
12 CAODC, www.caodc.ca
13 The Canadian Oil Driller, Rig Technician Making Progress, Spring 2005
14 The Canadian Oil Driller, A Background to Industry Training Initiatives, Spring 2005

Occupations by Alberta Apprenticeship and Industry Training as of January 2005, as well as others currently being developed.[15]

3.5.3. Recruiting Costs and Turnover

Season extension along with trade designation goes a long way to suggesting that drilling is a sustainable occupation, one worth getting into for more than quick and risky cash. One small but growing drilling contractor we spoke to estimated its recruitment cost at about $500 a head and first-year investment in employee training at about $1,000 a head. Many personnel come into the industry with basic training (e.g. first aid and H_2S certification) already in hand. The contractor we spoke to has experienced rising difficulty securing the right people for its crews and has been forced to become increasingly creative in order to attract good candidates. Costs for recruitment are consequently climbing. These costs are still viewed as worthwhile if the contractor can secure employees who can quickly become proficient, respected members of their respective teams. The cost of deficient skills and attitudes, noted our source, can be much higher than any outlay associated with hiring – they lead to safety and productivity issues and can result in deterioration of the contractor-client relationship.

Without load leveling in the industry, our contractor source suggested that the turnover rate for crew members would be well in excess of 50%. Prolonging the season offers employees continuing paychecks and a modicum of stability and allows this company to reduce its turnover rate to the neighbourhood of 20%. For a company with 10 active rigs, this lower turnover rate can generate savings in the order of tens of thousands of dollars. More importantly, it allows the company to maintain some integrity in its rig crews: not having to juggle or replace half of every crew every year, the crews grow some collective experience, allowing them to become safer, more efficient working units: high-performing teams. Consistently, operators remark that the pace-setting wells they drill are crewed by seasoned, communicative teams with a deeper consciousness for safety, and a higher ability to respond to challenges. The price tag on that is really in terms of customer satisfaction – which in this environment quickly translates to repeat or expanding or extended business if the particular contractor can reliably meet equipment and personnel needs.

Industry-wide, the difference between a 50% turnover and a 20% turnover rate can be quantified in simple terms as saved recruitment and training costs which, if we use $1,500 per person and assume about 12,000 personnel directly engaged on rig crews, translates to an industry savings of about $5 million annually. This may be a fraction of the true savings because:

- We are using $1,500 as turnover cost. Other industries estimate the cost of losing just one employee at $10,000. A KPMG-CATA study pegged the cost of one departing worker at $25,000. A *Business Week* article reported the cost of losing a typical employee as $50,000.[16] The cost of replacing a drilling employee may not be tens of thousands of dollars, but $1,500 is probably light.
- The total employed complement in the oil and gas service industry is in the range of 60,000 – five times the number of direct drilling staff. More consistent drilling activity will reduce turnover throughout the service sector.

Further, it must be taken into account that having the right rig crews is not only a matter of dollars and cents. Having well trained personnel with a good performance and safety track record is gaining strategic importance – i.e. the customers are noticing.

15 Alberta Trades and Apprenticeship Programs, http://www.tradesecrets.org/, Apprenticeship Update Index – Spring/Summer 2005
16 Bob Willard, The Sustainability Advantage – Seven Business Case Benefits of a Triple Bottom Line, New Society Publishers, Gabriola Island, 2002, p 28.

4. Indirect Benefits of Load Leveling

4.1. First Nations Sustainability

Much of what has happened "north of 60" in First Nations/Aboriginal dealings with the oil and gas industry is instructive for the situation in northern B.C. Aboriginals were opposed to oil and gas resource development a generation ago (during the days of intense Mackenzie Delta and Beaufort Sea exploration) in part because they were not involved, not consulted and saw no benefit for their people.[17] Today's approach to development in the North is marked by higher levels of Aboriginal interest and involvement. First Nations have become key players in determining training, equity participation and resource revenue sharing from resource development. Lessons from this earlier exploration period include the reality that if benefits from industry are not long-lasting, they may simply create social upheaval – particularly among the First Nations people. The strategy of the Northwest Territories is now to "use economic activity to strengthen our cultural and social network."[18]

Seasonal drilling load leveling in northern Alberta and B.C. offers the possibility of greater sustainability: greater planning of drilling programs, more concerted resourcing and training of crews (including more local hiring), cash flow through more months of the year. Borrowing lessons from north of 60 and learnings from the swiftly expanding complement of Aboriginal workers in the Fort McMurray oilsands area, the oil and gas industry is readier than it has been to address the interests, and concerns, of First Nations. Load leveling has the potential to become one of industry's more useful tools.

EnCana and the Fort Nelson First Nation are leaders in this respect. The two have been doing business since the early 1990s. EnCana, which holds large positions in a significant gas play east of Fort Nelson, announced in 2003 an $8 million joint venture with Fort Nelson First Nation and Ensign Drilling, whereby Fort Nelson First Nation will own and operate its own drilling rig.[19]

4.2. Stakeholder Impacts

Stakeholders in the oil and gas industry include landowners and northern communities whose economies for years have ebbed and flowed on the basis of natural resources. Increased drilling activity in recent years has brought with it an influx of capital and plentiful entrepreneurial and employment opportunities. The fact that, as a source of government revenues, the petroleum industry now outpaces forestry in B.C. and agriculture in Saskatchewan, speaks volumes as to the importance of the industry economically.

The industry has attracted complaints, however. The temporary nature of rig jobs, as well as the annually brief and longer term unpredictable duration of drilling activity, has limited the ability of local infrastructure to develop to support the industry. Rigs and crews are brought in from other parts of the WCSB; Alberta-based service companies simply follow the work from province to province. Money is made, and spent, quickly: communities seeking wealth and sustainability from the industry instead play unwitting host to problems associated with unwise spending (drugs, gambling and prostitution, etc.).

While load leveling will not change this situation overnight, it is definitely a step in the right direction. "Leveling out drilling will create a more predictable economy which in our view is a plus," says Karen Goodings, chair of the Peace River Regional District. "If you're going to be working here for nine months rather than three months, you're going to think more seriously about moving in – that's good for our communities."[20] Goodings would like to see the oil and gas industry ultimately playing a more integrated and visible role in northeastern B.C. communities.

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17 Speech "Maximizing Aboriginal Benefits from Resource Development in the Northwest Territories," Stephen Kakfwi, Premier, (June 18, 2001, Calgary)
18 Ibid.
19 British Columbia Treaty Progress: A Road Map for Further Progress, Business Council of British Columbia, Appendix 2, 2004
20 Karen Goodings, Chair of Peace River Regional District, Dawson Creek, phone interview, July 26, 2005

A recent newspaper article emphasized the advantages that northern B.C. residents are beginning to equate with the oil and gas industry.[21] “Fair Share,” the B.C. government’s program that returns a slice of resource revenues to the area for investment in local infrastructure, appears to be earning significant regional applause. B.C.’s actions to plow back royalty revenues into “road and pipeline building partnerships with energy companies” is also seen by northerners as achieving investment in a region that historically has viewed itself as a poor cousin to its Albertan neighbours. The B.C. government initiatives to encourage oil and gas drilling, including its summer drilling incentive, are viewed as being behind the generation of direct economic benefit for the area. Says Richard Dunn, an EnCana vice-president, “We couldn’t do our business without these programs. In B.C. it’s a package.”

There is work to be done. Landowners and surface rights groups are concerned about the cumulative impact of oil and gas drilling, regardless of the season in which it is carried out. Tourism advocates want to ensure that resource extraction activity does not foreclose on the potential of that industry. Underlying it all is concern for the integrity of the environment. Whether or not load leveling is part of its package of tools, the oil and gas industry is obliged to deliver more consistently on these sustainability issues, particularly in the north.[22]

4.3. Profit, Planet, People

The triple bottom line approach is not in widespread use within oil and gas, but it is increasingly endorsed by the leaders of this industry. Some of the biggest players are now closely watching the costs incurred (or saved) in arenas that are currently non-financial. First Nations sustainability and benefits to northern communities are only a part of it.

Overall, as examined in Section 3, it can be concluded that load leveling appears to present a strong case for the economic (“profit”) leg of the triple bottom line stool. Load leveling’s relationship to the environmental (“planet”) leg of the stool (more discussion contained in sections 5 and 6) can be characterized by a continuing imperative to respect the quality of air, land, water and inhabitants quality, regardless of the season of activity.

In terms of social benefit or equity (“people”), the final leg of the triple bottom line stool, load leveling appears to enjoy the potential for positive net effects ranging from First Nations sustainability through community viability to “human” elements that readily translate to financial impacts, such as easier recruitment, higher retention, higher team productivity, improved working conditions and improved public acceptance.[23]

Ultimately, even if operators are employing it only because they have no other choice to obtain the rigs and crews they need, load leveling will create an industry that is more committed to the areas in which it works. Significantly, it will create an industry that does (by necessity) a better job of planning its programs, its activity and its investments. This leadership in planning will engender planning and development in several other sectors: not only petroleum service and support but in education/vocational training, real estate development, public works, and retail.

21 Gordon Jaremko, “Northern B.C. happy with its Fair Share,” Calgary Herald, Oct. 6, 2005, p D4.

22 Phone discussion with Gwen Johansson, Custodians of the Peace Country Society, Hudson Hope, July 26, 2005

23 With insight obtained through a review of The Sustainability Advantage, Seven Business Case Benefits of a Triple Bottom Line, by Bob Willard, 2002.

5. Constraints on Load Leveling

5.1. Climate-Related Constraints

Physical “realities” make a difference to the extent of load leveling possible and affect the type of response an operator may have to the prospect of extending its drilling season. These realities vary from region to region (and even within regions), and they may also fluctuate from year to year. One group of realities that influences drilling activity consists of climate-related issues. The natural elements can wreak havoc on even the best-laid plans. These factors include climate change, ground temperature, air temperature, precipitation levels, and ground stability.

In order to analyze climate trends and variations, Environment Canada has classified the country into climate regions. As can be seen in Figure 40, the Northwestern Forest (dark green) and Prairie (yellow) regions correspond most closely with the WCSB. Seasonally concentrated (non-load-leveled) drilling occurs primarily in the Northwestern Forest region.

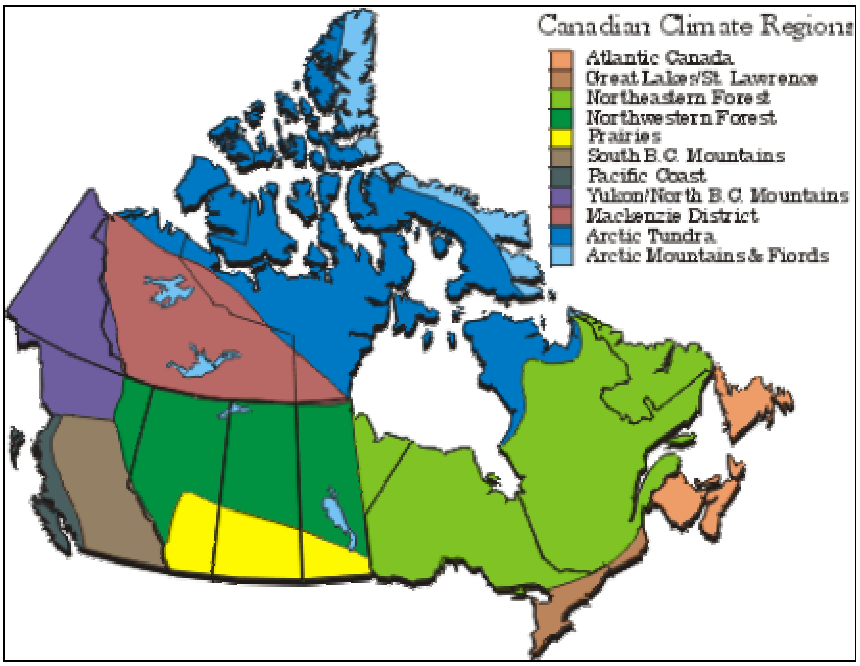

Figure 40. Canadian Climate Regions.
Source: Environment Canada

5.1.1. Climate Change

The unpredictability and uncontrollability of the natural elements make them challenging to contend with. One clearly observable pattern is that of climate change, or global warming. Climate change is challenging the traditional view that the winter months are a stable and predictable period facilitating productive oil patch work.

The winter national temperature departures table[24] from Environment Canada lists the years 1948-2004 in the order from warmest to coolest average winter temperature. The table data in Figure 41 reveals that five of the warmest 10 winters have occurred within the last decade.[25] With respect to load leveling in the WCSB, this warming can be expected to have the largest impact on northeastern B.C., where significant winter drilling activity currently takes place. Neither region has seen winter temperatures that would place in its top 10

24 Environment Canada, http://www.msc.ec.gc.ca/ccrm/bulletin/winter05/Ntable_e.html?region=n&table=temperature&season=Winter&date=2005&rows=58. “Departures” alludes to periods that significantly varied from the norm.

25 Environment Canada, http://www.msc.ec.gc.ca/ccrm/bulletin/national_e.cfm

coolest years since 1982. It is no longer as correct to say that the winter brings with it predictable or stable conditions within which drilling work can be optimally carried out.

Regional Winter Temperature Departures %		
Year	Northwestern Forest	Prairies
2000	4.1	3.8
2001	2.5	0.0
2002	3.2	3.7
2003	2.9	2.4
2004	2.6	2.1
2005	1.6	2.1

Figure 41. Regional Temperature Departures Showing Our On-Average Warmer Winters
Source: Environment Canada

5.1.2. Ground Temperature

In the WCSB, frost leaves the ground for the summer over the course of about a month stretching from May 15 in the south to June 15 in the north. A map showing the average dates of the last frost in spring across the WCSB can be found in Appendix C. The biggest determinant of frost persistence is air temperature. Climate change has created higher average seasonal temperatures in much of Canada, and the spring season has warmed more than any other season.

Regions that are becoming warmer are also seeing longer frost-free seasons, and this is occurring in most parts of Canada. Figure 42 shows that the most significant increases over the past century have occurred in B.C. and the Prairies. The orange dots indicate a longer frost-free season, and the larger the dot, the greater the change in season length. The blue dots, which are much sparser, represent a shorter frost-free season.

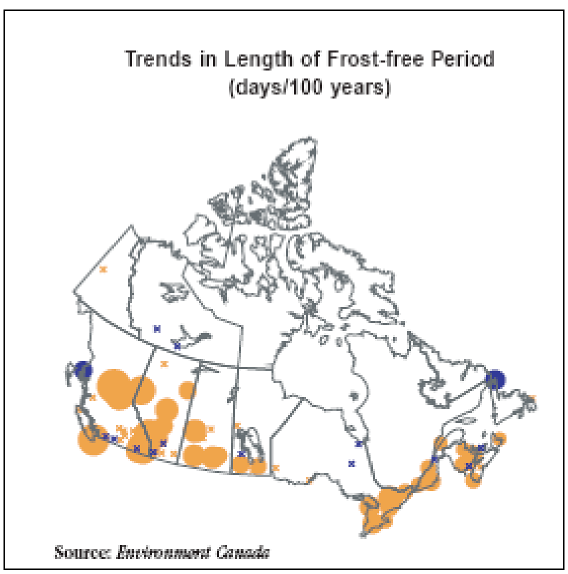

Figure 42. Trends in Frost-free Period.
Source: Canadian Council of Ministers of the Environment

Spring break-up, which precedes the last frost dates by two or more months, follows a south-to-north pattern. The period from approximately March through to May and even early

June are the most problematic months for movement of heavy equipment. While the frost-free season is, on average, getting longer, considerable variations can still occur from year to year. In much of Canada, the freeze-thaw cycles are happening more often, and repeated cycles of freezing and thawing in a single season are common.[26] These severe temperature swings contribute greatly to ground instability.

Further evidence of global warming can be seen in changes in permafrost. The oil and gas industry encountered significant challenges posed by permafrost in the 1970s, the period of intense Mackenzie Delta and Beaufort Sea exploration. Ground ice content is not generally a factor in the WCSB, but sporadic outcrops do appear in northeastern B.C. Warming climates will lead to thawing of permafrost and create less stable ground conditions. Building foundations, roadways, railways, pipelines and other structures are vulnerable to shifting, or settlement of the ground caused by thawing of permafrost.[27]

At the other end of the spectrum is extremely cold winter weather, which can make drilling operations and rig transportation uncomfortable and hazardous. Even with the evidence of climate change and the gradual rise in winter temperatures, severe cold snaps do still occur in the WCSB. Severe temperature fluctuations can be an even greater interference to drilling activities. Wide-ranging temperatures in a region can contribute to instability of ground conditions in any season, compromising best-laid plans and limiting an operator’s ability to complete a drilling program – summer or winter.

5.1.3. Precipitation

Another important climatic factor affecting drilling activity is precipitation. Total precipitation levels contribute to the presence of soft, wet land and precipitation in a given period can impede or even stall drilling progress. A series of weather stations around the WCSB provide us with a snapshot of precipitation levels through the study period. The charts appear in Appendix C. Precipitation levels are not substantial anywhere in the WCSB in the first or final quarters of the calendar year, as the rains typically begin in the second quarter and persist through the summer months. Central Alberta, northeastern B.C. and northern Alberta are particularly wet between July and September, when increased activity from load leveling would occur.

Although winter precipitation is typically not a cause for concern in the WCSB, the winter of 2004-2005 was an exception. The table data in Figure 43 show the regional winter precipitation departures for the past six years in the WCSB regions.

Regional Winter Precipitation Departures %

Year	Northwestern Forest	Prairies
2000	-33.7	-31.7
2001	-45.1	-39.5
2002	-42.2	-41.8
2003	-22.1	-21.0
2004	-22.6	-8.7
2005	23.1	-2.0

Figure 43. Regional Precipitation Departures Showing Generally Drier-than-Normal Winters
Source: Environment Canada

Environment Canada data show that in the Northwestern Forest region, spring precipitation levels have varied greatly over the past six years, ranging from significantly drier than average in 2002 to very wet in 2005. This variation, depicted in Figure 44, can significantly limit plans to load level and extend drilling activity past the first quarter.

26 Canadian Council of Ministers of the Environment , http://www.ccme.ca/assets/pdf/cc_ind_full_doc_e.pdf
27 Government of Canada, Climate Change Impacts and Adaptation, http://adaptation.nrcan.gc.ca/posters/articles/pr_09_en.asp?Region=pr&Language=en

Regional Spring Precipitation Departures %		
Year	Northwestern Forest	Prairies
2000	4.0	-17.3
2001	-5.0	-31.5
2002	-21.1	-27.5
2003	0.3	7.6
2004	3.5	14.9
2005	18.7	-8.5

Figure 44. Regional Spring Precipitation Departures.
Source: Environment Canada

5.1.4. Ground Stability

Wetlands are lands permanently or temporarily submerged or permeated by water. They are characterized by plants adapted to saturated-soil conditions. Wetlands are vulnerable to climatic variations and extreme events, and wetland areas occur across most of Canada. Wetlands include fresh and salt water marshes, wooded swamps, bogs, seasonally-flooded forest, muskeg, sloughs and peatlands – any area that can hold water long enough (and still enough) to let wetland plants and soils develop. Wetland location usually depends on local factors of drainage, topography, and surface material.[28]

Figure 45 shows the extent of wetlands in the WCSB. In the south and central regions of Alberta and Saskatchewan, wetlands do not pose a significant limitation to access. However in northeastern B.C. and parts of northern Alberta, they are a significant limiting factor to the transportation of heavy equipment outside of the winter months. As will be discussed in Section 6, mats have been used successfully to enhance access across soft, wet, saturated ground.

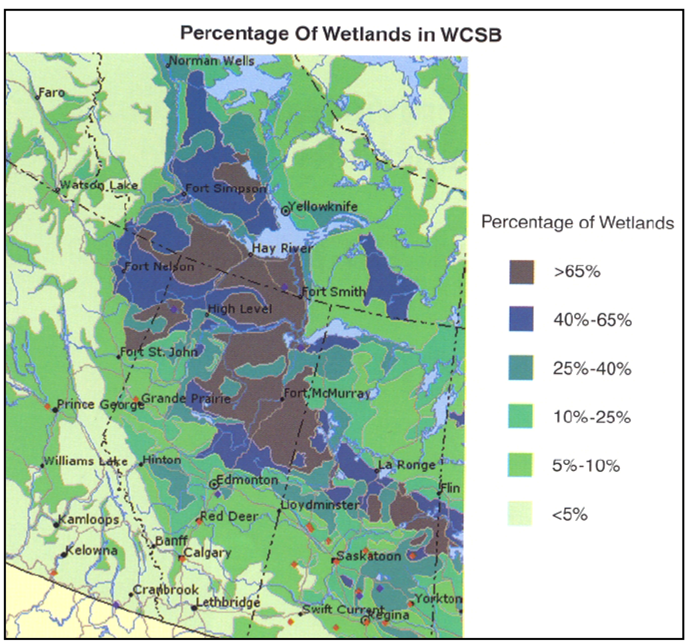

Figure 45. WCSB Wetlands.
Source: International Mat of Canada

28 Natural Resources Canada, http://atlas.gc.ca/site/english/maps/freshwater/distribution/wetlands/1

5.2. Access-Related Constraints

The second group of realities that can hamper load leveling is related to access. These factors include quality and extent of the road network, oversize permits to operate on the roads, road ban restrictions, environmental restrictions (for wildlife, sensitive terrain, etc.), and aboriginal land relations. We assembled the following information, providing perspective on these physical realities from region to region.

5.2.1. Road Network and Transportation Permits

Summer access by ground requires high-grade roads, whereas in the winter, ground access may be achieved across frost-hardened roads or ice. Winter roads are relatively simple and inexpensive to construct in comparison to all-weather roads.

B.C. is facing the challenges of building up its road network. It is a commonly held view in industry that, as a matter of simple logistics, the lack of an adequate road network limits drilling activity in B.C. The road network in the northeast of the province consists of public roads, managed by the Ministry of Transportation, and petroleum development roads (PDRs), which are built and owned by the oil and gas producers. Recent infrastructure initiatives on public roads undertaken by the B.C. government are discussed in Section 6.

PDRs are applied for and built by oil and gas producers, upon approval from the Oil and Gas Commission (OGC). PDRs may be winter-only or all-season access roads, and are applied for as part of a well application, or with a stand-alone application. Upon receipt of a PDR application, the OGC conducts an internal review process, which includes components such as forestry, land and environment implications (stream crossings, habitat assessments, etc.), coordination with other resource users, First Nations consultations, and public/stakeholder consultations. A typical PDR application takes between four and eight weeks to be completed. The process for a winter-only PDR is essentially the same as that for an all-season road, but the cost and preparation requirements for the operator can be less, which usually results in a shorter process.[29]

A recent concern in northeastern B.C. has become multi-agency coordination and planning when it comes to PDRs. There is a belief that government agencies could do a better job of coordinating the approval of these roads, and that planning could also improve between the oil and gas and the forestry industries. If the OGC or any stakeholder has issues with the application, the operator is able to make amendments to components such as timing, the access corridor, or the consultation process. Once a PDR has been approved and built, the owner of the road can charge user fees on the road.[30]

Transportation permits are another issue that B.C. has attempted to address. The B.C. Ministry of Public Safety & Solicitor General has made changes to its permitting system in order to improve the efficiency of the process. The province's 1-800 permit line was changed so that calls are answered more efficiently and effectively. Additionally, staff levels were increased at the Prince George scale, allowing faster processing, and also providing for better back-up coverage for the Dawson Creek scale. The Ministry also increased the load limits on its monthly term oversize and overweight permits, to parameters that are expected to cover between 75% and 80% of oversize loads that operate. Doing so has reduced the number of calls required by a company when arranging oversize permits.[31]

Our research did not reveal significant issues regarding the road networks or permitting processes in Alberta and Saskatchewan.

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29 Phone discussion with James Gladysz, B.C. Oil and Gas Commission, July 2005
30 Ibid.
31 Howard Emslie, B.C. Ministry of Public Safety & Solicitor General, July 2005

5.2.2. Road Restrictions

Road bans are typically intended to protect the road surfaces of secondary roads during periods when excess moisture (typically from snowmelt combined with frost leaving the ground) generates very soft, potentially impassable, ground. Typically, road restrictions are implemented first in the south and progress in a northerly manner across the WCSB. Restrictions normally begin in early March depending on weather conditions. Restrictions may be in place for up to six weeks from the date of implementation.

In northeastern B.C., efforts have been made to reduce the length of time and severity of road bans and weight restrictions by upgrading several key roads. Data from the B.C. Ministry of Transportation shows that over the course of the study period, the average road ban period was 75.6 days, compared to an average of 92.8 days for the five years prior to the study period. Additionally, the percentage legal axle loading on these roads during the study period was 75%, compared to 70% in the previous five years.[32] B.C.'s road infrastructure programs are discussed in Section 6 of this report.

In Alberta, road bans are implemented in order to minimize roadway damage, and this policy is implemented through a seasonal axle weight policy for overweight permits. The bans come on when the ground begins to thaw, which can range from early March in the south to the first week in April farther north. During road bans, the lowest level of axle weights is allowed, and in some cases, restrictions of less than 100% of legal axle weights are put in place. Road ban conditions typically extend until the end of June. Transporting rig components is still possible during the spring season, but it requires equipment with more wheels, and it increases the cost.[33]

In Saskatchewan, road restrictions typically start in the first week of March in the southwest of the province, and the rest follow over a two- or three-week period. Restrictions may be in place for up to six weeks, and may change on 48 hours' notice. If a prolonged cold spell occurs during the restriction season, the bans may be removed until conditions warrant their implementation again. Generally, only the thin membrane surfaced (TMS) highways or secondary highways are subject to spring road restrictions. Primary highways are not subject to spring road restrictions, except under extenuating circumstances. Additionally, rural municipalities are responsible for all municipal roads and issue their own overweight permits. Not all participate in the spring weight restriction program. Rural municipalities may also set weight restrictions lower than those published for Saskatchewan highways.[34] A map of Saskatchewan's primary and secondary roads is in Appendix C.

5.2.3. Environmental and Wildlife Restrictions

Environmental and wildlife restrictions may be imposed for a variety of reasons, including protection of wildlife and its habitat, protection of vegetation, and protection of water and air. Within this category, load leveling is impacted by restrictions imposed to permit seasonal movement or activities of wildlife, as well as to protect vegetation.

The B.C. Ministry of Environment has created Wildlife Habitat Areas (WHAs) as areas managed for selected species and plant communities that have been designated under the Forest Practices Code as "Identified Wildlife." A listing of WHAs in the Peace region of B.C. can be found online.[35]

32 Statistics provided by the B.C. Ministry of Transportation

33 Alvin Moroz, Alberta Transportation, July 2005

34 Saskatchewan Highways and Transportation, http://www.highways.gov.sk.ca/docs/trucking/weight_restriction_info/road_restriction_general.asp

35 B.C. Ministry of Environment, http://wlapwww.gov.bc.ca/cgi-bin/apps/faw/wharesult.cgi?search=wlap_region&wlap=Peace

Figure 46 shows the WHAs (in red) and ungulate winter range areas (in purple) in northeastern B.C.

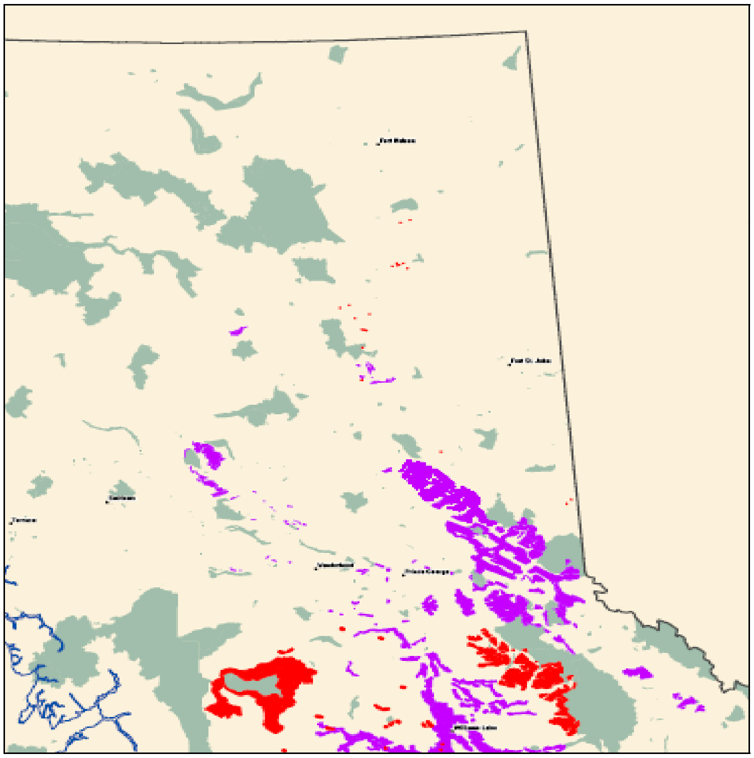


Figure 46. Wildlife Habitat Areas in Northeastern B.C.
Source: B.C. Ministry of Environment

In its Identified Wildlife Management Strategy - Procedures for Managing Identified Wildlife, B.C.'s Ministry of Water, Land and Air Protection notes that due to the limited number and size of WHAs, the possibility of a direct conflict with subsurface resource development is small.[36] It is noted, however, that oil and gas development in northeastern B.C. has contributed to the loss of caribou habitat in the area.[37]

The Muskwa-Kechika Management Area (M-KMA) comprises a unique and relatively undeveloped ecological region in northeastern B.C. The M-KMA is a 63,000-square-km area along the western edge of the WCSB. A requirement for pre-tenure planning has been established for a portion of the M-KMA. Pre-tenure planning does not prevent industrial access, but it does ensure that any socio-economic or environmental issues (possibly including timing of access) are addressed prior to sale of oil and natural gas rights and subsequent development activities.[38]

In Alberta, Sustainable Resource Development (SRD) has developed land use guidelines for provincial Crown land frequented by caribou, ungulates, and other species. The guidelines are primarily targeted to specific wildlife key areas/sites that play an essential role in ensuring the continued survival of local and regional populations of the identified wildlife species or species group.

"Caribou Protection Plans" are a requirement for industrial and commercial ventures on Alberta's public lands falling within caribou ranges. Typically, consideration of the spring/early summer calving period must be made. Protection plans for summer work must

36 B.C. Ministry of Environment, http://wlapwww.gov.bc.ca/wld/identified/procedures.html
37 B.C. Ministry of Environment, Accounts and Measures for Managing Identified Wildlife – Accounts V. 2004, http://wlapwww.gov.bc.ca/wld/identified/accounts.html
38 National Energy Board, The BC Natural Gas Market Overview and Assessment, http://dsp-psd.pwgsc.gc.ca/Collection/NE23-117-2004E.pdf

be submitted, reviewed and approved before any dispositions are approved. The map in Figure 47 shows areas particularly impacted. The Alberta government recently added enhancements to its caribou management program; details of these enhancements are not yet available to the public, but it is expected that they will add a greater level of protection for woodland caribou in the province.[39]

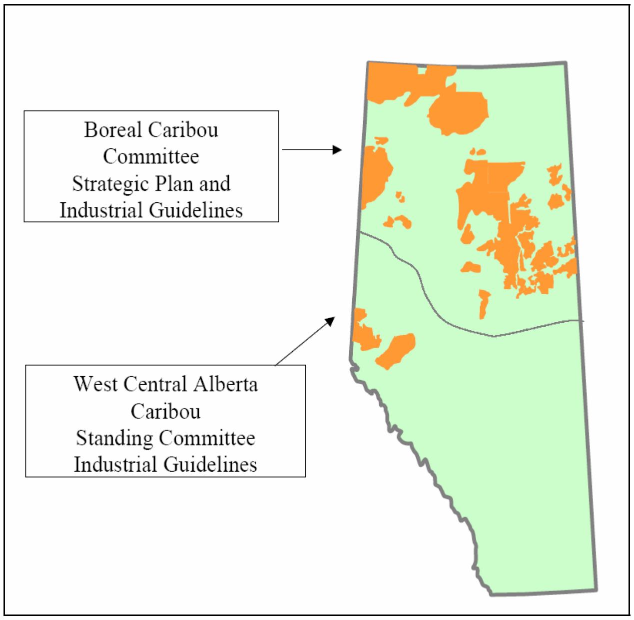


Figure 47. Caribou Regions in Alberta.
Source: Alberta SRD

Three general timing restrictions are applied to key wildlife zones: [40]

- Northern (Boreal) Alberta:
  - Jan. 15 to April 30
- Southern Alberta (except southwest corner):
  - Jan. 1 to April 30
- Southwest Corner:
  - Dec. 1 to Apr. 30 (mountains south of Kananaskis Country)
  - Dec. 15 to Apr. 30 (foothills south of Kananaskis Country)

There are also many types of vegetation (native prairie, etc.) that are protected by SRD in Alberta. Guidelines have been established and are applied as needed per region. The government's mandate is to prevent ground rutting and other ground disturbances. Such disturbances are a particular threat in the spring, when the ground is soft; therefore, some guidelines limit activity to frozen or dry ground condition. All-weather roads typically eliminate the risk of ground disturbance, so activities that use all-weather roads are generally unrestricted.

As a general trend, Alberta SRD is allowing more year-round activity. The department is, however, encouraging industry to increase its planning. Due to the increased level of activity on public land, the organization believes that the actions of different industries must be coordinated. For example, oil and gas companies should coordinate their activities with forestry companies, particularly in the north of the province.[41]

39 Government of Alberta, http://www.gov.ab.ca/acn/200506/18300A7809363-6C6B-4A4C-A856ADBB62549101.html
40 Alberta SRD, Land Use Guidelines for Key Ungulate Areas: http://www3.gov.ab.ca/srd/fw/landuse/pdf/UngulateWinterRange.pdf
41 Phone discussion with John Begg, Alberta SRD, July 2005

SRD uses Area Operating Agreements (AOAs) in order to gauge the level of upcoming industry activity. The AOA document outlines the planned activities for a company in the upcoming year. In 2003-2004, 19% of all oil and gas dispositions were subject to an AOA. The government is targeting a much higher level of AOAs in future years.[42]

In Saskatchewan, environmentally sensitive areas possess seasonal restrictions that protect environmental values such as: sensitive terrain, rare and endangered species, and stream and water body crossings. Such areas include areas of sensitive or fragile terrain and wetlands. Seasonal restrictions are in place in these areas because heavy equipment either risks causing significant damage under non-frozen conditions or simply cannot pass under non-frozen conditions. Examples of these areas include Great Sand Hills, parts of Manitou Sand Hills, and Cypress Hills in the south and floodplains and muskegs primarily in the north.[43] A map of the environmentally sensitive areas in Southern Saskatchewan is presented in Figure 48.

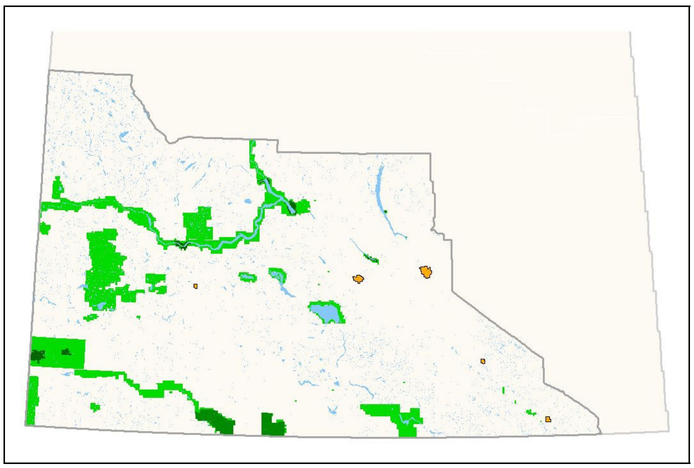


Figure 48. Southern Saskatchewan Environmentally Sensitive Areas.
Source: Saskatchewan Environment

Seasonal restrictions are applied on a case-by-case basis, with proposals being evaluated on their own merits. This applies to developments other than just oil and gas. Recent trends show industry becoming more aware of such requirements and responding with increased planning activities.[44] The overall percentage of drilling activity affected by seasonal restrictions is estimated to be very low. Historically, about 10% of drilling has occurred in environmentally sensitive areas. These activities are subject to an environmental planning and review process, and only a portion of these activities are subject to seasonal restrictions. It is estimated that about 5% of drilling activity in Saskatchewan is restricted to winter access for environmental reasons.[45]

5.3. Other Factors Impacting Load Leveling

What drives the drilling scheduling decision? A multitude of factors influences an operator's willingness and ability to alter the timing of its drilling program and, hence, load level. Some of them are directly related to the physical (climate, access) constraints just discussed, but there are other constraints. The following list of drilling decision drivers was developed through an examination of secondary sources and consultation with the Drilling Innovators Advisory Group. It constitutes a good summary of the factors that may stand in the way of more seasonally extended drilling activities:

42 Alberta Ministry of Sustainable Resource Development Annual Report 2003-2004
43 Graham Mutch, Saskatchewan Environment, July 2005
44 Graham Mutch, Saskatchewan Environment, July 2005
45 Ibid.

Budget strategies/approvals

- Imperative of cash preservation may outweigh more practical field considerations.
- Delays in having a budget approved can stall activity.

Contractor strategy/availability

- Smaller contractors would lock in for a longer season (i.e. commit their equipment) if they could.
- Contractors with more rigs may want to provide “swing” rigs (keep flexibility to provide rigs on short notice) at premium pricing.
- All contractors are interested in increasing/extending their rig utilization.
- Contractors face a battle to make experienced crews available in a timely manner.
- Corporate performance expectations
- Desire to show investors early results (i.e. production flows) may drive the decision to drill as much as possible as early as possible in the year.

Cost

- Boiler and fuel costs are higher in colder months.
- Services may go at a premium in winter when capacity is stretched.
- These costs tend to be offset by prohibitive access costs in summer months.
- Part of the cost argument may be perceptual (i.e. rooted in traditional practice rather than current reality).

Environmental considerations

- Drilling can be delayed or interrupted for seasonal wildlife activities … e.g. breeding, nesting, migration.
- ERP (environmental resource planning) considerations – there is potential for damage to sensitive areas.
- Large companies in particular must be good stewards.
- The public expects industry to comply.

Government incentives

- B.C. has introduced incentives to drill between April and November.
- B.C. has introduced incentives to extend road network (therefore increase year-round drilling access).
- Alberta and Saskatchewan governments have not introduced similar incentives. B.C. is currently deciding whether to extend its load leveling incentives.

Infrastructure availability

- Extent of roads is a key driver – presence of all-season roads greatly expands potential for year-round drilling.
- Supply constraints (e.g. diesel shortage) are a factor – when whole industry is operating at capacity, there is a potential for busts.

Lease expiry, land sales

- Operators drill wells simply to hold a zone (five years’ lease expiry).
- Operators drill in order to prove/disprove production.
- Operators may be compelled by a partner deal to drill by a certain deadline.

Physical or seasonal constraints

- Road bans due to wet/soft surfaces interrupt access and therefore drilling.
- Typically these are a factor in second quarter.

Regulatory approvals

- The pace/promptness of well licensing or larger area exploration permitting is a factor.

- Typically the regulator wants drilling to occur when the fewest people are around (e.g. avoid Bragg Creek's summer recreation crowd) – this is particularly the case for sour wells.
- Approval times vary … they tend to be fastest in Alberta, a little slower in Saskatchewan, somewhat slower yet in B.C., slowest in NWT.
- Public consultation may be required, which significantly impacts the schedule.

Safety considerations

- Safety is a function of the availability of experienced crews.
- The weather contributes to less safe conditions in winter.
- Having an experienced team together through seasons is an advantage.
- A way to keep a crew together (i.e. reduce turnover) is to keep it busy beyond winter season.
- High performance expectations in the first quarter can lead to injuries which can force premiums up and make it more difficult to attract workers.

Stampede and summer holiday factor

- The city of Calgary shuts down for Stampede; very little goes forward in July.
- This early-summer downtime sometimes precipitates a lag in activity in August and September.

Technology

- Some types of rigs may be more amenable to year-round drilling – larger rigs are typically better winterized, but not much differentiates the rigs in terms of summer operability.
- Coil tubing and other productivity enhancements have made long jobs short, creating flexibility and improving overall drilling economics.
- Availability and affordability of season extenders (e.g. mats, heliportable systems).
- Practicality and risks associated with emerging technologies (e.g. airships).

Workforce constraints

- Employee availability (the industry tends to pick up people in late summer/early fall)
- Workforce skills and experience.
- Using workers more days of the year turns drilling into a sustainable "trade" around which careers can be built.

6. Load Leveling Enablers

The climate- and access- related constraints to extended season drilling are well documented and, in the minds of some operators, daunting. But progress has occurred in surmounting many of the obstacles. This section first compiles factors that may affect the timing of drilling and then proceeds to a discussion of “enablers” that are helping, or have the potential to help, the oil and gas industry achieve more seasonally leveled drilling activity.

6.1. Policies Encouraging Load Leveling

Widespread support has been voiced for load leveling at the governance levels: industry associations, government departments and regulatory bodies. The Petroleum Services Association of Canada (PSAC) has advocated load leveling on behalf of its members for years. The Petroleum Human Resources Council of Canada, in a 2003 report, cites a skills shortage as a key issue for the WCSB; the industry’s seasonality is seen as an impediment to attracting and retaining a skilled workforce. Rigs can be understaffed, which leads to safety issues.[46] B.C. is the only jurisdiction thus far, however, to put forth a fiscal commitment to match verbal encouragement of load leveling. Taxpayers and industry alike appear to be reaping the rewards of its program.

6.1.1. The B.C. Incentives

In 2003, B.C.’s Ministry of Energy, Mines and Petroleum Resources introduced its *Oil and Gas Development Strategy for the Heartlands.* Its keynotes were:

- A royalty reduction program for drilling deep wells in mountainous terrain.
- A road infrastructure program offering royalty credits for road building (started at $10 million in 2003, increased to $30 million per year for 2004 and 2005).
- A summer royalty program offering a royalty deduction of up to $100,000 or 10% of the goods and services cost of each well spudded in the spring, summer and fall months, effective through 2005.

The premise of the strategy was to improve access to resources, extend the drilling season thus providing more stable, year-round jobs, increase economic activity in B.C.’s heartlands communities, and increase revenues to the province. Advantages identified for companies who undertook summer drilling were:

- Shifting the workload at the Oil and Gas Commission (OGC) away from the peak period, thus improving administrative effectiveness.
- Drilling in summer provides for an opportunistic selling price when wells begin producing at high rates in the fall and winter when prices are traditionally high.
- The incremental summer wells will be accelerated providing a time value for money benefit.[47]

The program appears to have had significant impact. Drilling figures from the OGC, as seen in Figure 49, demonstrate significantly increased summer drilling. B.C. has seen an increase of more than 100% over the study time period. For purposes of comparison, Alberta’s increase is close to 40%, as shown in Figure 50.

46 Petroleum Human Resources Council of Canada, The Strategic Human Resources Study of the Upstream Petroleum Industry: The Decade Ahead, http://www.petrohrsc.ca/english/news.html

47 B.C. Ministry of Energy, Mines and Petroleum Resources, http://www.em.gov.bc.ca/Publicinfo/OilGasStrategySupport_Materials/oil_and_gas_strategy_default.htm

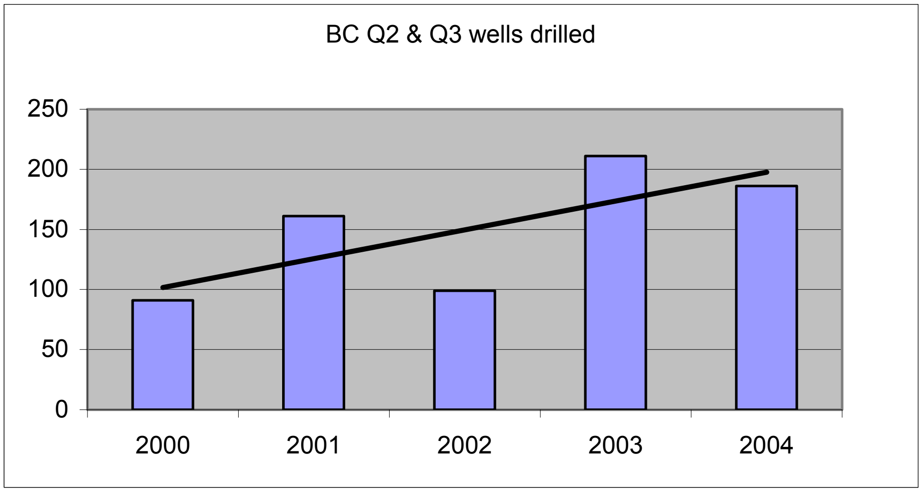


Figure 49. B.C. Summer Wells Drilled 2000-2004.
Source: B.C. Oil and Gas Commission

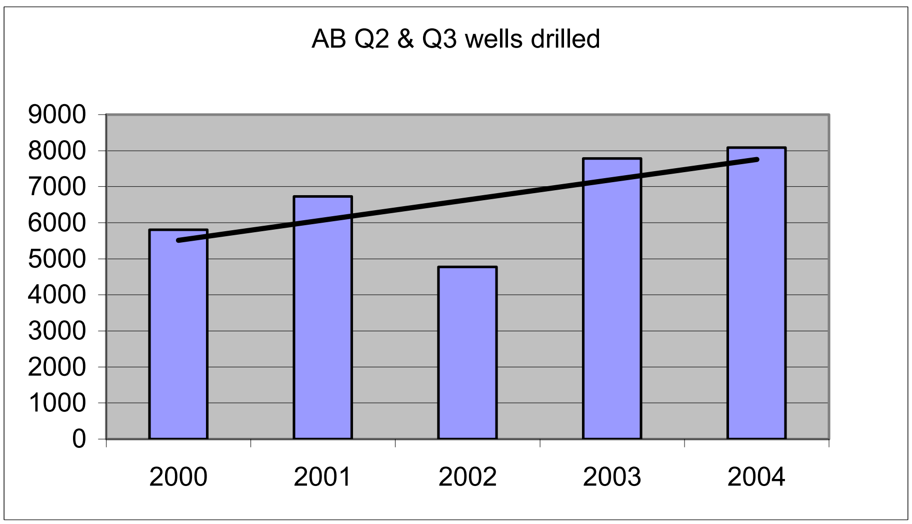


Figure 50. Alberta Summer Wells Drilled 2000-2004.
Source: Alberta EUB

A brief description of the B.C. government programs and incentives relevant to load leveling is presented below. This is followed by a brief analysis of the effects of the programs, as measured through public drilling data records. Lastly, industry feedback on the B.C. programs is provided.

B.C. Summer Royalty Program

The Summer Royalty Program was introduced in May 2003. The program allows for a deduction toward drilling and completion costs. The amount is the lesser of 10% of costs attributable to well, or $100,000, multiplied by the producer's proportionate interest in the well. The program applies to wells spudded between:

- July 1 and Nov. 30, 2003
- April 1 and Nov. 30, 2004
- April 1 and Nov. 30, 2005

At this time, the Ministry is undecided as to whether this incentive will be continued past 2005.

B.C. Infrastructure Initiatives

The Infrastructure section of the B.C. Ministry of Energy, Mines and Petroleum Resources has undertaken several key initiatives in recent years, with the overriding goal to develop the oil and gas industry in the province. A map of the infrastructure programs undertaken in the region is presented in Appendix C.

Oil and Gas Initiative Phase 2 (OGI2)

This six-year, $100-million road improvement program was completed in 2004. Upgrades were made to seven key public roads, including the Liard Highway, Beatton River, Buick Creek, Prespatou, Milligan, and Cecil Lake Roads. OGI2 helped to create a network of roads capable of supporting year-round industrial traffic. The template for the roads was a hard surface nine-metre-wide deck with 3:1 side slopes wherever possible. The goal of the upgrades was to reduce the requirement and scope of bans and restrictions on these roads.

Heartland Oil and Gas Road Rehabilitation Strategy (HOGRRS)

This project is a five-year road rehabilitation program, funded by the province, which upgrades public roads and trunk roads located throughout northeastern B.C. It is a continuation of the OGI2 program. The primary objective of HOGRRS "is to extend the drilling and service season by reducing the impact of seasonal road restrictions or bans."[48] Currently in the middle of its second year, a number of important roads are slated to be upgraded to the same road template of OGI2, including Heritage Highway, Boundary Highway, Fort St. John Hub, Farrel Creek, Upper Halfway, and Andy Bailey Roads. Last year, $18 million was applied under HOGGRS and this year is on track for $32.5 million of road rehabilitation. The roads included in the HOGRRS were recommended for improvement by several oil and gas producers in the area.[49]

The Public-Private Partnership (P3) SYD Road

A major infrastructure project undertaken in the region has been the Sierra Yoyo Desan (SYD) Road upgrade. The partnership agreement between the Ministry and a private road contractor was signed in June 2004, and the road upgrades are expected to be completed in December 2005. After the upgrades, a 14-year maintenance program will be used, in which the road contractor will be responsible to the Road User Group, which represents the 50-plus companies that pay user fees to use the road. The user fees will be collected by the Ministry, and then passed on to the road contractor. The Road User Group also acts on important issues related to the road, such as safety.[50]

Royalty Credits for Infrastructure Development

The Royalty Credit Road Program provides $30 million in royalty credits annually for new and upgrading of resource roads. The Ministry provides up to 50% of the construction costs to operating companies in the form of royalty credits. Following strong positive responses from industry, the province increased the annual contribution in November 2003 to $30 million from the original level of $10 million.

6.1.2. The Effects of B.C.'s Programs

The effects of B.C.'s government programs and incentives on drilling activity can be measured using public drilling data records.

Figure 51 displays drilling activity, as measured by rig days, in northeastern B.C. during the

48 B.C. Ministry of Energy, Mines and Petroleum Resources, http://www.em.gov.bc.ca/subwebs/oilandgas/infrastructure/rehab/rehab.htm
49 Lee Burton, B.C. Ministry of Energy, Mines and Petroleum Resources, July 2005
50 B.C. Ministry of Energy, Mines and Petroleum Resources, http://www.em.gov.bc.ca/Publicinfo/SierraYoyo/June_04_announcement/SYD_p2.pdf

study period. Total yearly activity in the region has increased substantially, from approximately 5,000 rig days in 2000 to approximately 10,000 rig days in 2003 and 2004.

As the blue line on the chart indicates, a first-quarter peak in B.C. drilling activity has been a consistent feature over the study period. These peaks have remained about the same height, with the value hovering near 4,000 rig days for the years 2003-2005.

The telltale aspect of the analysis is that the valleys of activity, common in the second and third quarters, have been somewhat leveled off over the past two years. The second- and third-quarter numbers for the years 2003 and 2004 are noticeably higher than the previous years' numbers. This suggests that the increase in total yearly drilling was accomplished by increased drilling in seasons other than winter. The second quarter, in particular, shows substantial increases from 2000 to 2005.

The red line indicates a hypothetical analysis: if summer drilling had remained the same as the 2000 to 2002 averages, and the yearly increase in activity was only accomplished in the first quarter, how much increase in winter drilling would have been needed to achieve the yearly total? The result is that the first quarter "peaks" would have had to be between 6,000 and 7,000 rig days, 60% higher than what actually occurred. There is some question as to whether this level is actually achievable. Due to the sustained level of 4,000 rig days in the first quarter, it is reasonable to wonder if this is the maximum that the contractors, service companies and infrastructure can currently handle.

The conclusion drawn from this examination of B.C. drilling activity is that there was significant load leveling occurring in B.C. in 2003 and 2004. This load leveling occurred not by shaving off the winter peaks, but by filling in valleys in the other quarters. This has enabled a significant increase in drilling activity on a yearly basis without contributing to additional first quarter frenzy.

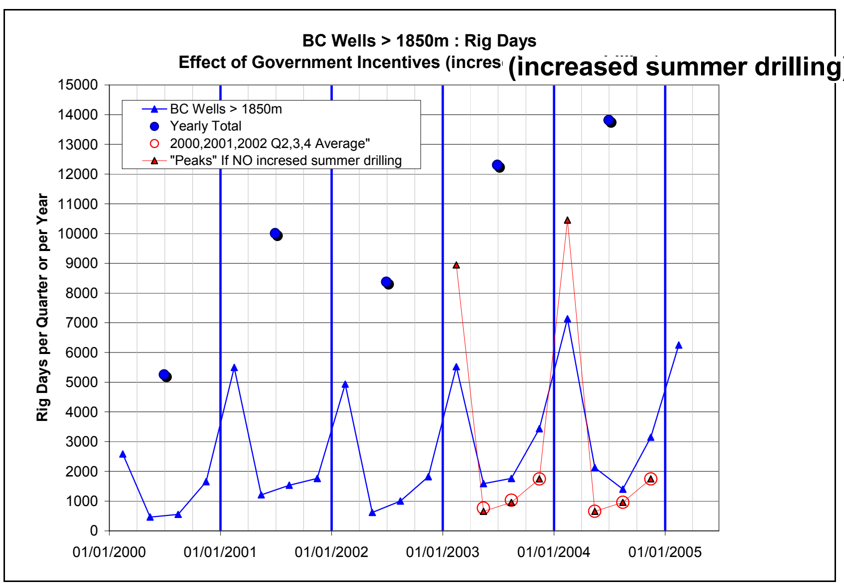


Figure 51. B.C. Wells Drilled - Effects of Government Incentive Programs.

6.1.3. Industry's Perspective

Industry feedback on the B.C. programs was provided by operators interviewed regarding their experiences in northeastern B.C.

The Summer Royalty Program received somewhat mixed feedback. One operator interviewee remarked that for his company, which is currently not focused on extending its drilling season, this incentive is not enough to interest the company to pursue summer drilling in B.C. He remarked that, in reality, this decision is determined by the corporate culture and planning cycle. His company utilizes a September-to-August budgeting cycle; the expectation is that the bulk of drilling will be done in the winter. In his opinion, the monetary amount of the incentive is not the issue.

A second operator is involved in summer drilling in northeastern B.C., and is currently focused on increasing its drilling season in the region. This company's perspective is that the Summer Royalty Program does help to promote summer activity in the region, when it is used in combination with other programs. The operator has taken advantage of several programs available in B.C.

A third operator noted that this incentive is very useful in encouraging summer drilling, as it helps to offset the cost of using facilitating technologies such as mats.

The feedback obtained regarding the infrastructure programs undertaken by the Ministry of Energy, Mines and Petroleum Resources and the Ministry of Transportation is very positive. The programs are seen as being critical to improving the road network in the region, thereby increasing year-round access.

The Royalty Credit Road Program is seen as a useful lever for encouraging infrastructure development in the region. One operator stated that the 50% savings on road construction costs is very significant, because it allows the company to apply those savings to further drilling activity in the region. Saving this money allows the company to focus on its business, which is drilling. If the company has money to spend on either road construction or on drilling, its obvious preference is to spend it on drilling.

Similarly, a second operator stated that the Royalty Credit Road Program has been very effective at allowing his company to expand its operations in the region. The main benefit is that the program has helped to offset some of the large, up-front capital expenditures that would often make spring and summer activity prohibitively expensive. This operator also noted that the combination of credit roads with other incentives, such as the Summer Royalty Program, and other benefits of summer drilling, such as lower rig and service fees and longer-term rig contracts, allows the return on investment associated with summer drilling to approach that of winter drilling.

Feedback from the operators interviewed confirms that the infrastructure in the region has vastly improved over the past several years. One operator noted that the roads have improved significantly, particularly in the Fort Nelson bridge area. A second operator stated that the Royalty Credit Program and the SYD P3 partnership have provided access to much of the territory northeast of Fort Nelson. Another operator comment was that the HOGRRS has upgraded many kilometres of roads that are used extensively by his company. It was also mentioned that infrastructure in B.C. will likely always be a constraint on operations, to some degree, but that the proper steps to minimize this are being taken. Also noteworthy were the increased load restrictions from 64 to 85 tonnes for crossings in the South Peace area.

Comments on the B.C. government and its programs to encourage industry development in the region were very positive. It was noted that the proactive position of the Crown in recent years has been instrumental in providing safe, cost-effective, and timely access in the region. Also mentioned was that communication with the government is much improved and that the Ministry personnel are easy to reach and responsive.

When asked for ideas about what else the B.C. government could do to encourage summer drilling, one operator noted that for companies not currently seriously considering this option, it would be helpful for the Ministry to compile a detailed presentation of the success stories in the region. This would allow the Ministry to communicate how other companies have been successful in the region, the steps they have taken to get there, and the types of benefits these companies have received. He felt that this would be a good way to convince some managers of the potential gains to be made by pursuing summer drilling in B.C. He envisioned this as a detailed, sit-down presentation with information on how to save money on drilling in the area.

Another notable comment was that increasing operations in B.C. is a function of hydrocarbon occurrence and that, all else being equal, an operator will go where the oil and gas resources are. This operator noted that the B.C. government has done a good job in setting the province on equal footing in areas such as operating and other costs, risk and potential, and regulatory implications. The company feels there are currently no disincentives in operating there.

6.2. Load Leveling and Environment Sensitivity

To gain understanding of how environmental and wildlife restrictions can impact drilling activity, we interviewed an operator with significant operations in a west-central Alberta region affected by several wildlife management areas. The species protected in this region include caribou, sheep and goats, trumpeter swans, and others.

This region accounts for 30-35% of this operator's drilling activities and production. Planning becomes very important, primarily because of the increased chances of missed windows of opportunities for drilling. Each year the company creates an Area Operating Agreement (AOA), which outlines the regional plan for the upcoming year. Most of the large operators in the area have developed an AOA. The first component of an AOA is a description of the company's core operating procedures, best practices and administrative documents. The second is essentially a list of the company's proposed operations, and is updated and reviewed with Alberta SRD seasonally.

The restrictions that most impact the company are timing restrictions and, for summer drilling, restrictions that limit the distance of a well site from a major road. For example, in caribou zones, an all-weather access road can only be constructed if it is within 100 metres of an existing main road. Activity beyond this 100-metre distance is not prohibited; however, access is only possible by using matting to access the location, or by construction of a low-grade, dry-weather-only road. Each of these two options has drawbacks, which prevent most companies operating in the area from utilizing them. Using mats to construct a road can be seen as cost-prohibitive because of rental charges, as well as mobilization and demobilization activities. Construction of a low-grade, dry-weather-only road often restricts drilling operations because operations must be shut down each time material precipitation affects the area.

Timing restrictions on activity are somewhat flexible, depending on the particular type of wildlife restriction, the Forestry branch, and most importantly, the current environmental conditions. For example, exceptions have been granted to extend the operational time period if the company has shown good faith in doing work under an "early in, early out" philosophy, in which work gets done quickly and in respect of the rules and guidelines. This leeway depends heavily on the relationship that the company has built with the government. The company also works quite closely with the forestry industry in the area. Many of the roads are owned by a large forestry company, and the companies are in close contact, especially during the road ban season. Cooperation and planning are viewed favourably by the government.

The operator noted that restrictions on summer activity increase the pressure to complete drilling activity during the winter months. The importance of this region to the company makes it imperative that it maximize usage of the region; knowing that summer activity is limited means that more drilling must occur in the three winter months. There are resulting implications for requirement of more rigs, personnel, and supporting services.

Directly across the provincial border, the company does not experience noteworthy wildlife restrictions. In B.C. the limiting factor to the operator's summer drilling is a lack of road access on high-grade roads. There are also more muskeg and soft areas to navigate. The company believes that wildlife restrictions could be in development in B.C., particularly for caribou management.

In 2005, in this region, the company is as load leveled as it has ever been. The company has the same number of rigs running now (summer 2005) as it plans to have in the region during the upcoming winter season. As the region evolves into a more developed state, it will be more beneficial to maintain continuous, year-round drilling. The more established a company is in the region, the more sense it makes to drill year-round. As more wells are drilled, more high-grade roads will be built. As for company-wide activities, a winter ramp-up is still expected, as there are other operational regions that are still considered winter drilling regions.

For this company, well costs are typically case-specific. In general terms, in the west-central Alberta region, it has been historically cheaper for the company to drill in the summer. Cost savings in the summer typically arise from avoided costs in the areas of boilers and fuel, camp costs, and rig rates. It was noted, however, that rig rates in the summer of 2005 are no lower than they were in the previous winter season (although the rates are almost surely to rise for the upcoming winter season). Additionally, it has been observed that crews can work more efficiently in the summer when working conditions are less harsh. Conversely, costs that typically rise in the summer include access costs, depending on the type and length of access road that must be constructed. For example, a long road for which clay and shale must be brought in can be very expensive to build.

Also noted was that keeping a rig and crew busy throughout the summer brings the advantage of having the high-performing rig and crews utilized for the summer, and continuing so into the winter. Conversely, starting up a rig in the latter part of the year can bring its own problems, such as a poorly-performing rig and potentially greener crew. It can be assumed that a crew starting up in the fall will be somewhat under-performing, while the high quality ones have been running year-round.

It was also stated that the limiting factors to load leveling are not always wildlife- or weather-related. Capital management can be an issue, in that the company is committed to working within its budget for the year, and limiting summer activity is one way to ensure that money will still be available when it will be needed for the winter season.

6.3. Technologies and Practices Supporting Load Leveling

6.3.1. Heliportable Drilling

As discussed, weather and the environment can be limiting factors on load leveling. Helicopter transportation can extend the drilling season by avoiding limitations placed on operations by soft ground, inclement weather and road bans. Heliportable operations are much more common in other oil and gas producing regions than in the WCSB.

A 2003 study commissioned by the B.C. government explored the feasibility of heliportable drilling in the Muskwa-Kechika Management Area (M-KMA) in northeastern B.C. The report concluded that heliportable drilling is feasible in the area, but that the feasibility will vary, depending on site-specific circumstances. The study identified six critical factors that affect the site-specific feasibility of heliportable drilling: environmental sensitivity; availability of low-cost alternatives; helicopter site risk; capital cost; blow-out risk and worker safety; and presence of sour gas. Given their broad nature, these factors are applicable, in principle, to other areas within the WCSB.[51]

Environmentally, heliportable drilling avoids most of the long-term physical impacts of road development, such as landscape modification and increased conventional access. Two impacts that are attributed to heliportable operations are increased widespread noise and increased potential for displacement of sensitive wildlife species. In most cases, however, relatively less physical impact will be associated with heliportable drilling.[52]

51 The Muskwa-Kechika Management Area Heliportable Drilling Feasibility Study, 2002
52 Ibid.

Technical feasibility of heliportable drilling depends on the availability of depth-rated heliportable drilling rigs and the ability of helicopters to deliver critical levels of support in mobilizing, drilling, and completing a deep sour gas well. The influence of weather on heliportable transport is estimated as minor, but weather delays that could have an impact include high wind, low cloud and fog cover, and icing conditions.[53]

The economic feasibility of heliportable drilling depends heavily on site-specific access costs. There is, generally, a linear relationship between distance and cost for heliportable drilling, whereas the costs of conventional access (roads) are much more variable due to terrain, weather patterns, and assessment and engineering requirements. Heliportable drilling appears to be more expensive than conventional access for short distances, but less expensive relative to longer and more complex roads through sensitive terrain.[54] A short access well may contain a few million-dollar premiums for heliportable service, which equates to an approximate 30% increase in conventional costs for short access.[55]

Discussions with a provider of heliportable well servicing solutions provided valuable insight into the evolution of heliportable drilling in the WCSB. Currently in the WCSB, helicopters are being used to service wells. The company introduced a heliportable service rig to the WCSB two years ago. This technology demonstrated the possibility of doing more in the well bore and has enabled the development of other heliportable services. Heliportable servicing helped emphasize the cash flow advantage of being able to service well sites year-round, without losing valuable months of production by waiting for ground access to the site.

This company spent much time and effort developing this market over the past five years, as it found attitudes and practices within the industry difficult to change. But change has occurred. Over this period, the company has seen a change in its customers' mindsets and spending habits. For example, the company believes that operators are now allocating more capital spending into the second and third quarters, rather than allocating capital money in the first quarter and having to spend operating dollars in the second and third quarters. The previous practice of not allocating capital dollars past March often hindered the ability to load level.

The company's perspective is that acceptance of heliportable solutions has been growing slowly but steadily in the WCSB. Barriers are still faced, such as the belief by some that heliportable operations are not feasible and are too cost-prohibitive. The company estimates that heliportable operations cost approximately double that of conventional operations. This cost differential is attributed to the operating costs of the helicopters. The current high level of commodity prices is compelling companies to look more seriously at helicopters as a potential solution. Also contributing to the increased interest in helicopters is the smoothing of the cyclical nature of natural gas prices.

Of the company's 65 helicopters, the large majority are typically deployed in the areas along the Alberta/B.C. border. The company expects to embark on heliportable drilling activity in B.C. early next year.

6.3.2. Mats

Mats are a technology being used throughout the WCSB. For companies looking to reduce or eliminate the effects of inclement weather on drilling activity, particularly heavy precipitation that can occur in the spring and summer months, mats appear to be providing a solution. Mats allow for more confidence that drilling deadlines can be met, as they help ensure that inclement weather will not affect drilling schedules. This allows for greater confidence in the timing of drilling programs. Facilitating activity on soft ground, mats provide

53 Ibid.
54 Ibid.
55 Muskwa-Kechika Management Area, http://www.muskwa-kechika.com/pdf/June2002ApprovedRecords.pdf

a stable base on which equipment can travel and operate. One operator we spoke with compared mats on mud to snowshoes on snow – it just makes getting around easier.

It is important to note, however, that simply having mats on hand is not a guaranteed solution. Pre-planning is required to ensure that the mats can be used effectively. A company is required to have an adequate supply of mats and have the mats in the right location. Using mats is still somewhat dependent on the road network, as a company must avoid impact of road bans by planning ahead and having equipment in place before bans take effect.

Any area within the WCSB with soft or wet ground is a good candidate for mats. Mats are noted to be most useful when a company is drilling multiple wells in one area. In these situations, mats make the most economic sense. Mats are also cost-effective when the distance to cover with matting is not excessive. An industry rule of thumb is that mats can be effectively used to access well sites that are within four kilometres of a road. Building more than four kilometres of access with mats is not often economical.

According to a mat supplier interviewed, the demand for mats in the WCSB has seen strong growth over the past few years. Mats can be rented or purchased by operators. Current estimates for Western Canada are that 65,000 mats are available for rental, and 33,000 mats are currently owned by operators. The market is now at the point of nearly 100% utilization of the available mats.

Technological improvements are being made to mats, with synthetic materials recently entering the market. Wooden mats, such as oak, are still popular, but the new synthetic composite mats have advantages, such as being easier to clean, and being lightweight, which saves on transportation costs.

Mats do add cost to drilling activity. Costs include purchase or rental price, transportation, installation, maintenance, storage, and replacement. Similarly, important considerations when using mats include road bans, bridge weight restrictions, alternate routes, vehicle volumes, and the importance of communication among departments (construction, drilling, completions, pipelines, and facilities).[56] In B.C., mats are being utilized to reach well sites that are farther from main arteries. The Summer Royalty program (with a maximum of $100,000 per well) helps to offset the cost of mats in these areas.

There is little doubt that mats can help companies with year-round access to well sites. The technology works, and success stories exist. The use of mats is also gaining a higher profile, as a recent article in a national newspaper demonstrates. The article notes the use of mats has allowed a major operator in the WCSB to move its 1,000-tonne rigs over sponge-like muskeg in a rain-swamped area between the northern borders of Alberta and B.C. Mats are noted as helping to “change the way Canada’s energy industry operates when temperatures climb and frozen land turns into waste-deep muck.” The growing popularity of mats is also captured: “The mats, which are laid out to make temporary roads that allow the heavy equipment to move over soft ground, are selling like giant hotcakes.”[57]

Despite such glowing reviews, real barriers to increased mat usage do exist, including the traditional operational cycle and traditional mindsets within companies. Some operators are embracing the opportunity and taking advantage the opportunities presented by mats, while others are very reluctant to change. It was indicated to us that the tide is starting to turn and that more companies are increasing their planning horizons and incorporating new ideas into their plans. The success stories within the industry are having an impact, as companies have always paid close attention to what their competitors are doing.

56 International Mat of Canada, http://www.newpark.ca/mat/index_mat.html

57 J. Harding, “Mats help oil and gas producers tame muskeg”, The Financial Post, August 9, 2005, http://www.canada.com/national/nationalpost/financialpost/story.html?id=6c8ea295-fa72-45d6-8c4c-1de4aec187d8

According to operators using mats to perform non-winter drilling, mats have been very effective at extending the drilling season. One operator interviewed estimated that 40% of his company's drilling operations now include mats. He stressed that the mats must be used properly, and like any piece of equipment, they must be maintained. This operator uses mats extensively in the western Alberta foothills, in northern Alberta, and anywhere else if wet conditions exist. The biggest benefits touted by this operator include the ability to extend the drilling season, the ability to leave a smaller footprint, and a cleaner and safer work environment. He compared the use of mats to being as comfortable and clean as working on a paved lease or a paved road.

6.3.3. Road Restoration

The Road Badger is a piece of road restoration equipment used to rehabilitate and extend the serviceability of gravel, cold mixed, oiled and dust abated roads. The machine was specifically designed for rehabilitation and product conservation of aggregate based roads. The company is based and operates in Nisku, Alberta. A picture of the Road Badger can be found in Appendix C.[58]

The performance of the machine has received favourable reviews from various sources. An Edmonton-based engineering firm compared costs between traditional oiled road maintenance and the Road Badger operation on a number of road sections. These comparisons indicated a cost savings of $1,600 to $3,785 per section or from $500 to $1,000 per hour of Road Badger operation.[59]

Additionally, a major oil and gas operator used the Road Badger to rehabilitate 115 kilometres of rugged oil field roads in the muskeg country of northeast Alberta. The Road Badger provided significant road maintenance cost savings in comparison to re-gravelling the same sections of road. This improved surface condition also resulted in reduced equipment repair and maintenance costs. The company saved over $2 million in product and associated costs over a five-month period, when including savings from fuel, aggregate material, and emission reductions. As a result of these positive results, the Road Badger has received repeat business and a strong endorsement from this operator.[60]

6.4. Technologies with Potential Application to Load Leveling

6.4.1. Airships

Airships are a technology from the past currently being reborn because of technology advances in building materials and avionics. The great airships of the Zeppelin age had to be enormous to carry passengers around the world simply because of the airships' weight. The new airships, such as the Zeppelin NT, are being made of lightweight and very strong materials that create more possibility of lifting payloads. "Buoyed" by issues associated with global warming (including melting permafrost, less dependable ice bridges, etc.), interest in the freighting potential of airships finally appears to be "aloft."

The potential advantages of airship transportation are similar to those of heliportable transportation: avoid road ban and soft ground restrictions, leave a smaller ground footprint, and work in warmer temperatures and more daylight, allowing for safer working conditions and less consumption of heating fuel.

Compared to helicopters, airships offer the potential to leave a smaller footprint in terms of noise and wind, to carry heavier loads at lower operating costs, and to reduce stand-by charges (which various sources suggest constitute a substantial portion of the cost of a remote drilling site).

58 Road Badger Inc., www.roadbadger.com
59 Aggregates & Roadbuilding Magazine, http://rocktoroad.com/reconstructing.html
60 Road Badger Inc., www.roadbadger.com

If airships are ultimately successfully applied in the drilling industry, it will be because someone has come up with a demonstrable, low-cost solution to the problem of ballast. When a lighter-than-air ship offloads heavy freight, it must either release its lighter-than-air gas (helium is very expensive) or take on ballast (e.g. sand) to offset the loss of its freight. This greatly reduces the feasibility of any application involving the remote delivery of rig pieces.

Certainly industry is interested in reducing the cost associated with airborne rig transport. The payload capacity of helicopters tops out at about 20 tonnes, which in the case of rig transport means multiple trips. Operating costs can be $20,000 an hour, with a requirement for three hours of maintenance for every hour in the air. Helicopters fly faster than airships, but actual time constraints are principally associated with the need to truck rig parts a certain distance and then break them down for helicopter transport.[61]

Lighter-than-air airships are in use in Europe to transport passengers (a tourism application). Zeppelins can hold more than a dozen passengers and can move relatively swiftly (upwards of 150 km/h). In the oil and gas industry their potential application is for crew changes. Airships are also currently under consideration for a multitude of communications/monitoring duties at high altitude (potentially accomplishing the tasks of a satellite at a fraction of the cost). On the cargo side, they are under investigation by the U.S. military, which is looking to develop the capacity to move large invisible loads to hot spots anywhere in the world. So-called “sky cranes” have a range of 300 kilometres and travel at speeds of 50-80 km/h, with an operating cost significantly lower than that of helicopters. Their major limiting factor is that they need to offload and reload ballast.

6.4.2. Hybrid Aircraft

Short take-off and landing (STOL) aircraft incorporating airship technology – they can be considered hybrids – are a focus of research in the U.S. military. These craft are intended to fill a long-range, heavy cargo mission: upwards of 500 tonnes of payload. The hybrid aircraft land on any flat surface, such as snow, ice, and water, which makes it capable of operating independently of ground-based infrastructure. This feature will make the hybrid an ideal aircraft for resource development in remote areas such as the Arctic. The estimated time to prototype is five years. Military funding is being made available to design and build a 30-tonne demonstrator.

6.4.3. Canadian Advancements

Soccer-ball-shaped “spherical” airships incorporating a ballasting solution (pictured in Appendix C) are a focus of research in Canada. Spherical airships have lifted 75 tonnes in the past (although the ballasting problem has not been demonstrably solved). Two significant steps still separate the Canadian concept from commercialization: the construction and testing of a craft that demonstrates the ballasting solution; and commitment from a customer to put the craft into use. Proponents believe that within three years the first step will be taken. 21st Century is the company in Canada that will design the craft, and the developers are looking to partner with an air services company to operate them. The project has received initial interest from a Canadian oil and gas producer and Sustainable Development Technologies Canada (SDTC). Should this venture proceed on schedule, the drilling industry would be well advised to monitor its potential for application to the load leveling challenge posed in northern B.C. and Alberta.

61 Jim Thomson, personal communication, August 2005

7. Conclusions

This project set out to generate a communicable "business case study and companion presentation for reducing winter drilling activity and spreading that activity out more evenly throughout the year."

Key findings of this study include:

- Drilling efficiency has improved significantly in the WCSB over the last five years. Load leveling is already extensive in the south part of the basin, but has not yet been carried out in any great measure in the north. Drilling performance is better in the south. Overall, despite the fact that the first quarter of the calendar year is the busiest time for drilling, drilling efficiency is in no way superior at this time of the year.
- There are drilling cost advantages for load leveled operations, particularly for wells with shallow to intermediate depth profiles. The cost of drilling a well in a winter-only field can be 25% to 100% higher than the cost of drilling a comparable well in a field that sees year-round activity. The key is continuity: regardless of the season, drilling programs that proceed without interruption are more efficient.
- Perhaps the largest advantage associated with using non-winter months to bring a well to production is the reduced time from spudding to production. The benefits are far in excess of extra costs that may be required to do this.
- Load leveling can save capital and associated costs by extending utilization of the existing drilling fleet. In fact, in a better leveled environment, it should be feasible to drill the same number of wells annually with 10% to 15% fewer rigs.
- Incident (accident) rates do spike during periods of high activity in the WCSB. The first quarter sees not only more incidents but incidents at a higher rate: as much as one third higher than the rates seen at other times of the year.
- Employee turnover associated with concentrating workload into one quarter of the year can be as high as 50% and load leveling has the potential to reduce this to the more manageable neighbourhood of 20%.
- Indirect benefits of load leveling to First Nations as well as northern and other remote communities in the WCSB include jobs, permanent (as opposed to transient) residency, community support, improved public infrastructure and entrepreneurial opportunities.
- B.C.'s summer drilling incentive program is working and appears to be a win-win for industry and government. Many operators treat the incentive as a bonus – the extra nudge to pursue what already looks like a good idea. A few operators may not yet see the size of the incentive as adequate make load leveling initiative worthwhile – although for these operators there appear to be additional reasons, including traditional mindset, as to why load leveling is not yet on their agenda.
- Operators are pursuing a number of innovative load leveling practices, and season-extending technologies are gradually rising to the challenge. The road mat business, in particular, is fully engaged in meeting the rising needs of industry. Other developing technologies may further encourage load leveling activities.

In summary, there is a strongly positive business case for the continuation and expansion of load leveling behaviour. We have allowed for the considerable variance that exists in the data and in our assumptions by attempting to generate ranges of benefits and by limiting our conclusions to the conservative sides of those ranges. Incremental annual benefit to industry can be summarized as follows:

Industry Benefit From Load Leveling		
		Annual Benefit
Lower well costs	$	110,000,000
Advanced production	$	420,000,000
Avoided rig construction	$	45,000,000
Reduced incident rate	$	45,000,000
Reduced turnover	$	5,000,000
	$	625,000,000

The figures above can be viewed as the minimum gross values that can accrue to the drilling industry through more aggressive load leveling behaviour. They incorporate cautious assumptions of commodity prices. At the time of printing, for example, natural gas was trading at double our assumed price; if we employ the revised figure the annual benefit would climb beyond $1 billion.

Even at $1 billion, this annual benefit is modest when weighed against the annual capital expenditure in B.C., Alberta, and Saskatchewan on exploration and development activities (excluding oil sands, capital spending was $24.4 billion in 2004).[62] The reality is, regardless, that operators opting to pursue aggressive drilling programs without seasonally leveling their drilling activities will find good equipment and safe, high-performing crews much harder to come by. Analysts' short-term expectations may currently discourage the incremental expenditures required to achieve load leveling, but the market can be a two-edged sword; we believe that investors will ultimately punish underperformance stemming from reluctance to load level.

Several factors still stand in the way of increased application of load leveling. As a small but germane example, moving future-year costs into the current year in order to level a drilling program is not a step that any market-sensitive oil and gas producer would take lightly. Based on the findings of this business case, it appears to be important that efforts be undertaken to better communicate and educate industry as to the benefits of load leveling. The role of the Drilling Innovators Advisory Group in regard to load leveling, in fact, may be far from complete – a significant and worthwhile endeavour over the coming year may be to use this business case and its components to spur dialog within the industry, leading ultimately to greater understanding of the advantages, greater will to invest in leveling activities, and greater ability within the industry to achieve seasonal extension of drilling.

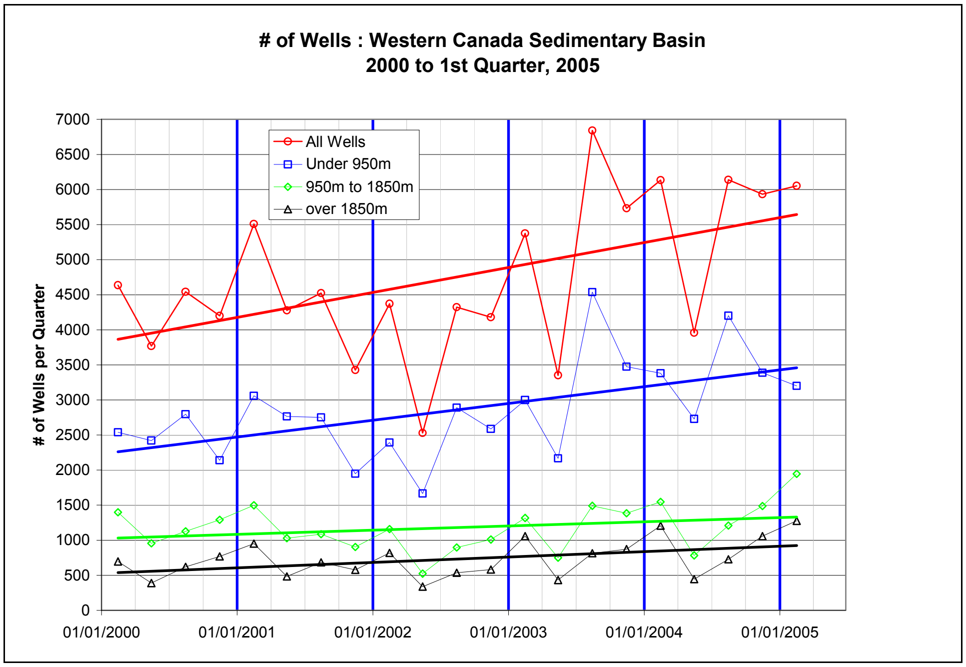
62 Canadian Association of Petroleum Producers, 2005: http://www.capp.ca/default.asp?V_DOC_ID=40

Appendices

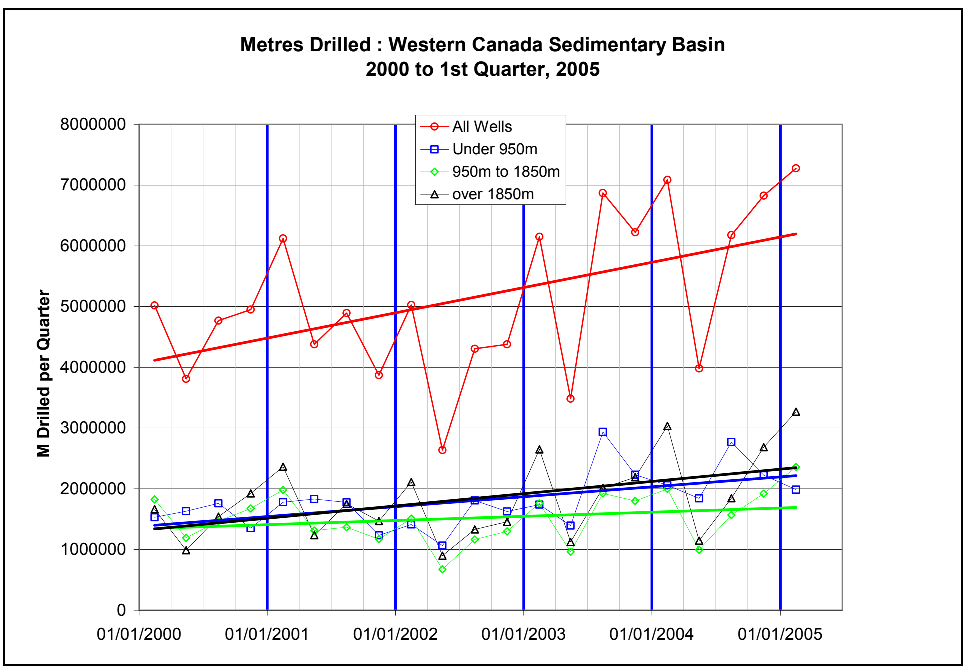
APPENDIX A – Scope of Work

1. To examine drilling performance results of projects benefiting from seasonal load leveling, and to compare these results against projects performed under more traditional peak season circumstances.
2. This project will:
   i. Estimate the cost implications to companies that engage in seasonal load leveling.
   ii. Estimate the safety benefits to companies that engage in seasonal load leveling.
   iii. Estimate the industry-wide dollar implications of load leveling.
   iv. Estimate the industry-wide safety benefits of load leveling.
3. Attempt to identify the best practices associated with seasonal load leveling.
4. Attempt to identify reasons for year-to-year variability in seasonal load leveling.
5. Identify and understand the application of innovative technologies or practices allowing the extension of the drilling season.
6. Measure the impact of the seasonal load leveling incentives offered by the Government of British Columbia, and to assess how the incentives affect decision-making in industry.
7. This project will be confined to the WCSB and will include wells drilled in Saskatchewan, Alberta and British Columbia.
8. This project will base its findings on data from the 2000-2004 drilling seasons. Using this time period will allow for the identification of recent trends in drilling activity and for a determination of the impact of the load leveling incentives offered by the B.C. government.
9. There will be no attribution to specific industry sources on specific input received unless approved by the specific source.
10. Make best efforts to be substantially complete by June 30, 2005.

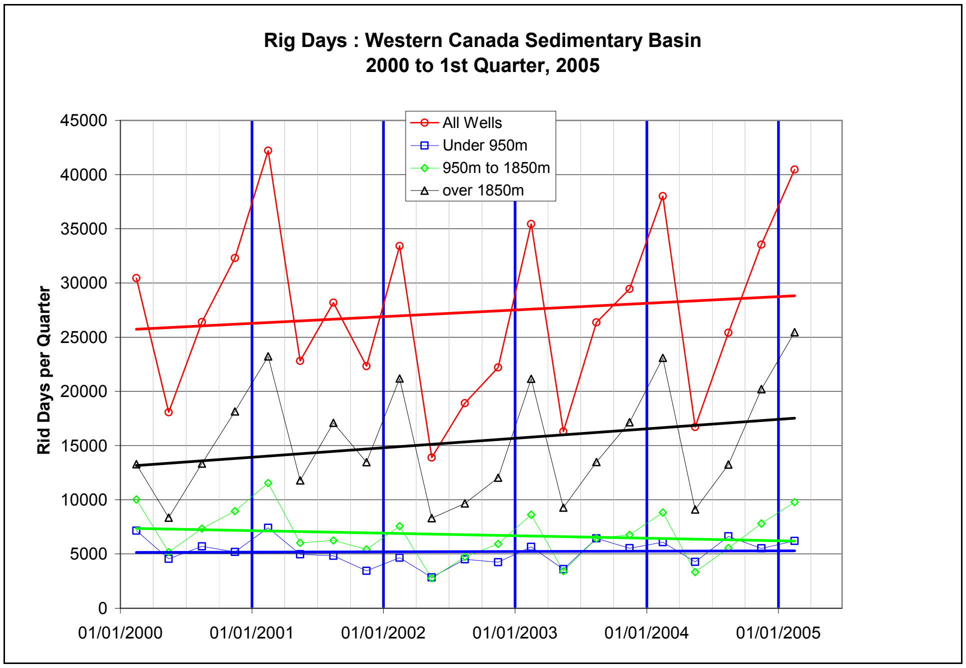
APPENDIX B – WCSB Drilling Activity Summary



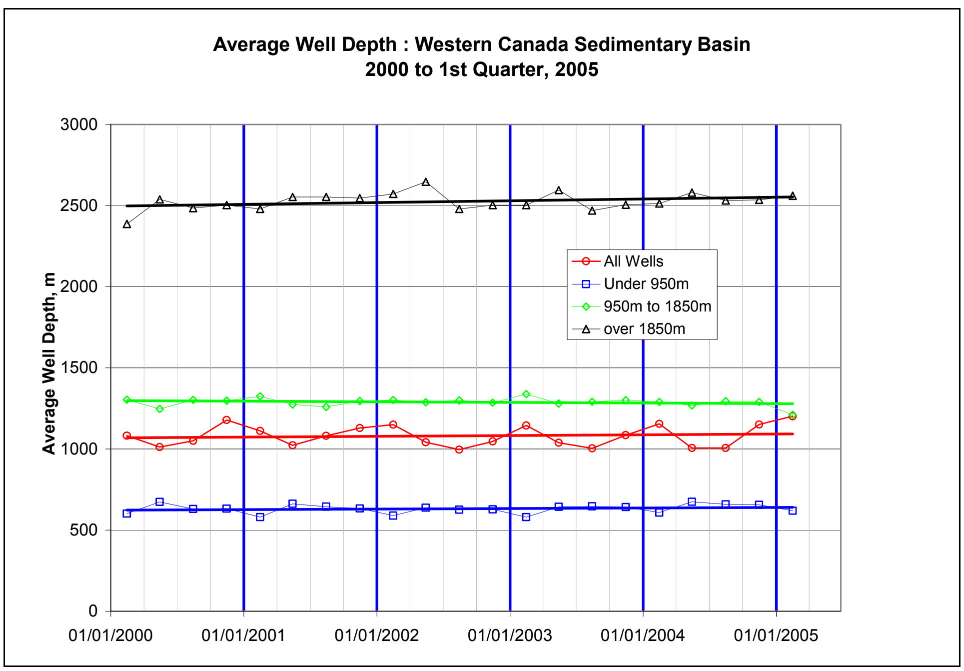
Source: Nickle's DOB



Source: Nickle's DOB



Source: Nickle's DOB



Source: Nickle's DOB

APPENDIX C – Supporting Figures

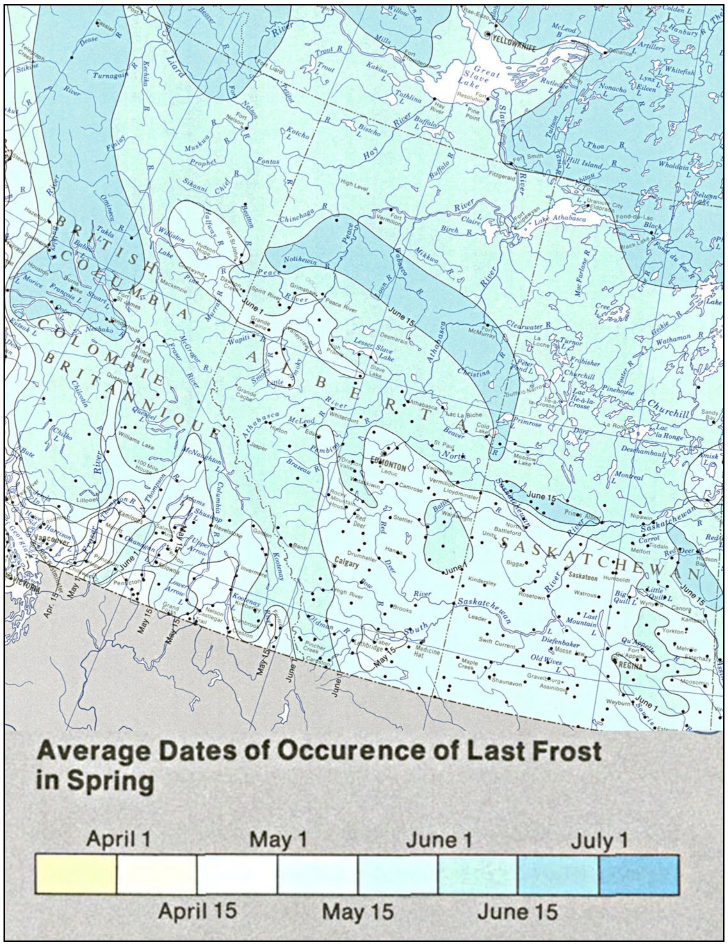


Figure 52. Average Last Frost Dates.
Source: Natural Resources Canada

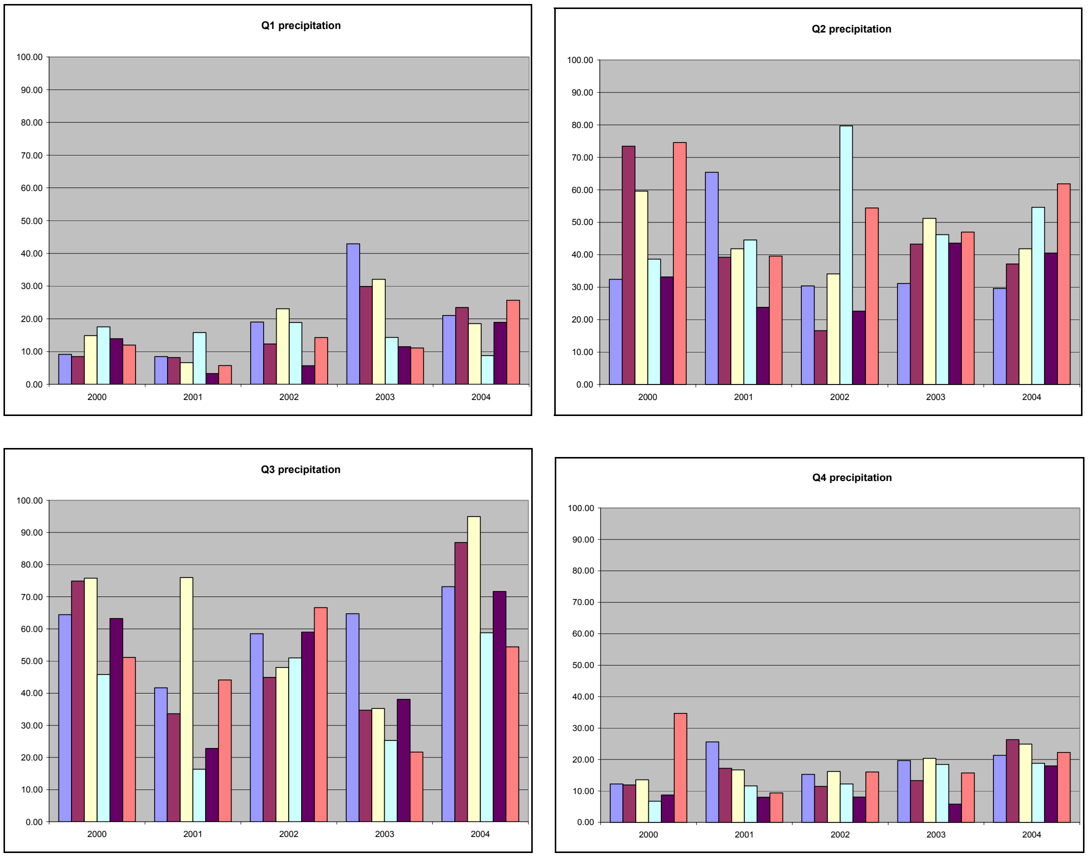
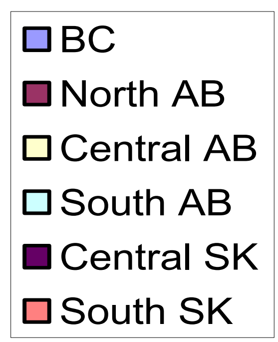


Figure 53. Regional Precipitation Levels.
Source: Climate Canada



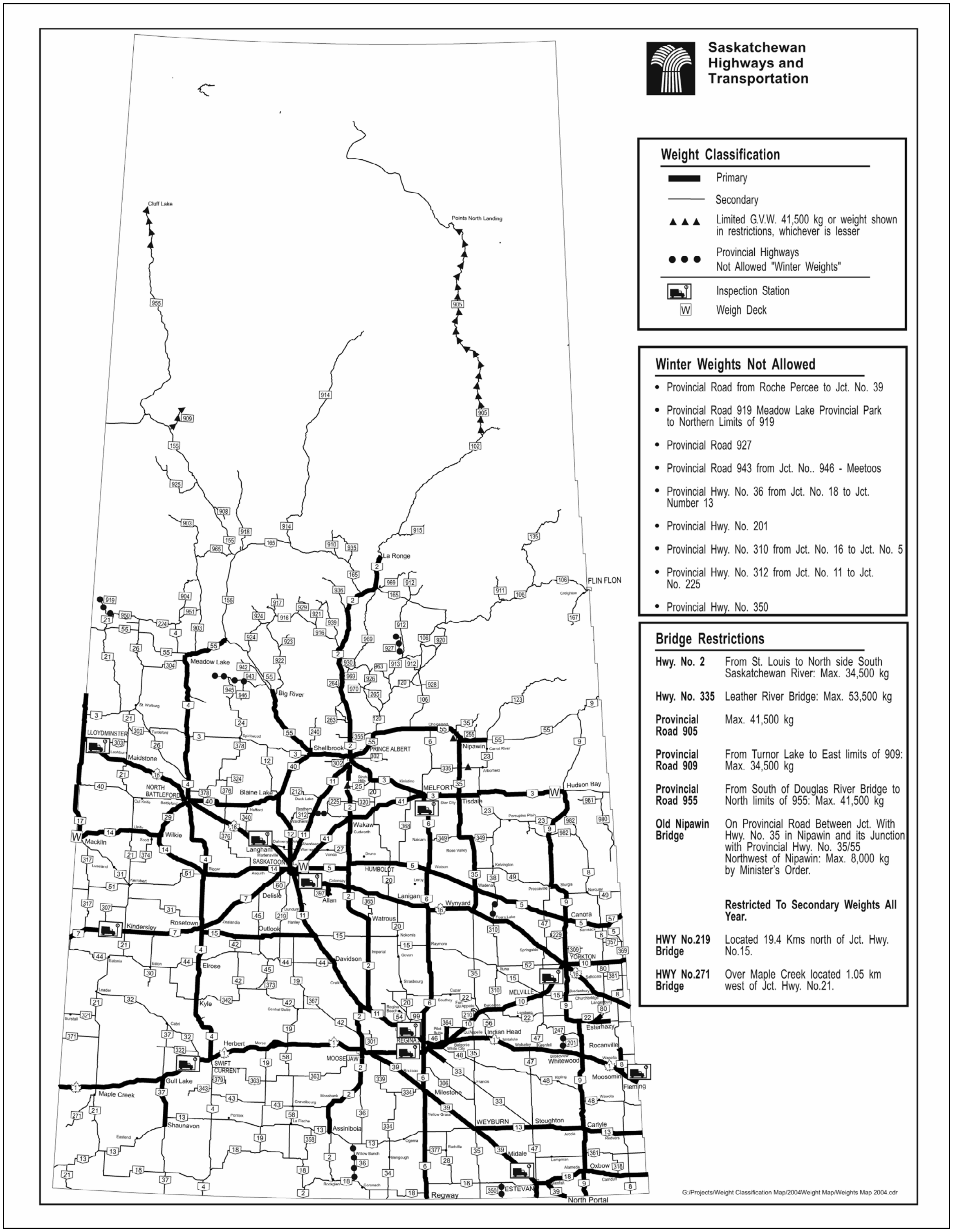


Figure 54. Saskatchewan Provincial Highways.
Source: Saskatchewan Highways and Transportation

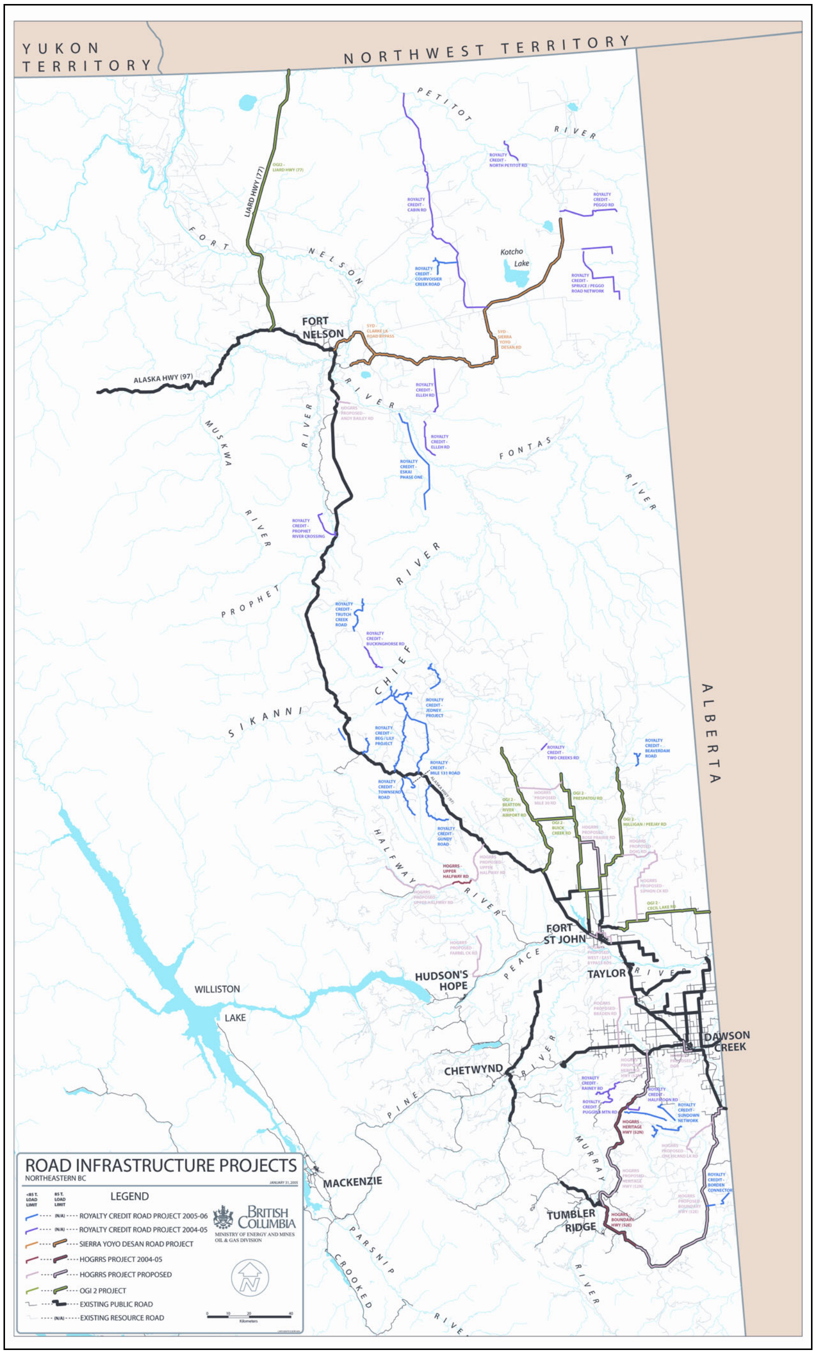
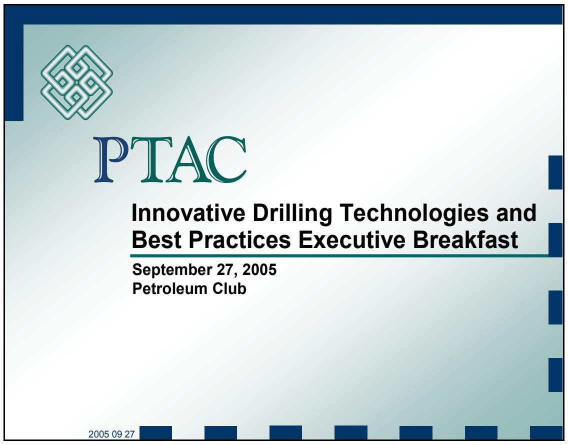


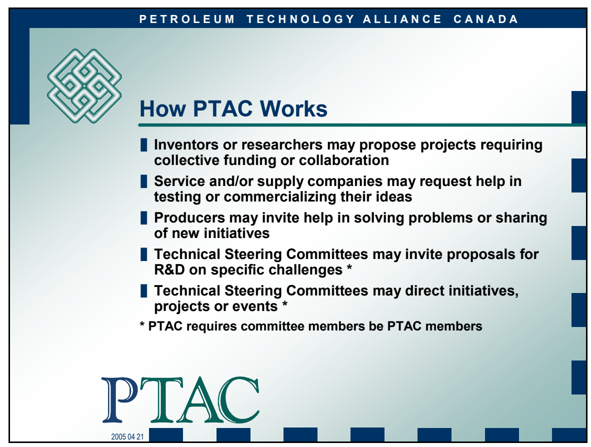
Figure 55. B.C. Road Infrastructure Programs.
Source: B.C. Ministry of Energy, Mines and Petroleum Resources

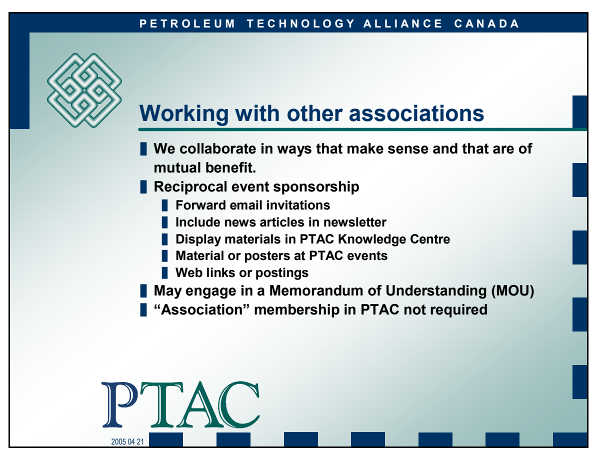
Figure 56. The Road Badger.
Source: www.roadbadger.com

Figure 57. Spherical Airship.
Source: Isopolar Airships

APPENDIX D – Summary Presentation Package







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Committees and Working Groups

Research
- Air Issues Research Planning Committee
- Ecological Research Planning Committee
- Soil Research Planning Committee
- Salinity Working Group

Technology
- Weathered Hydrocarbon Project Committee CO2 Enhanced Hydrocarbon Recovery (EHR) Steering Committee
- Drilling Innovators Advisory Group
- Driving Safety Working Group
- Natural Gas and Conventional Oil Recovery (NGCOR) Energy Innovation Network (EnergyINet) Advisory Group
  - EnergyINet Increased Recovery of Oil and Gas Business Case Working Group
- Shallow Gas Technology Planning Committee
- Technology for Emission Reduction and Eco-Efficiency (TEREE) Steering Committee
  - TEREE Marketing Subcommittee
  - TEREE Project Evaluation Subcommittee
- Unconventional Gas Technology Roadmap (TRM) Steering Committee
- Water Innovation Planning Committee

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Other Current Significant PTAC Projects

- EnergyINet Increased Recovery of Oil and Gas Business Case
  - Goal is 5 billion bbls oil & 25 TCF gas incremental recovery
  - Project performer is EPIC with Sproule, Fekete, U of C, ARC +
  - Cost is $ 900,000 for AB, BC and SK
  - Weblink: http://www.ptac.org/res/rest0402.html
  - Completion June 2005
- EnergyINet Conventional Heavy Oil R&D Needs Including GHG Intensity Reduction
- EnergyINet Oil and Gas Related R&D Information Collection
- Unconventional Gas TRM

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Drilling Seasonal Load Leveling Business Case

- Purpose was to develop and present a coherent, complete and compelling argument for greater drilling seasonal load leveling in the WCSB, capturing benefits relating to:
  - Drilling costs
  - Safety performance
  - Human resources
  - Rig utilization
- Set out to generate a communicable "business case study and companion presentation for reducing winter drilling activity and spreading that activity out more evenly throughout the year."

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Recognition

- Alberta Department of Energy
- B.C. Ministry of Energy, Mines and Petroleum Resources
- Burlington Resources Canada
- Canadian Association of Petroleum Producers
- ConocoPhillips Canada
- EnCana Corp.
- Nexen Inc.
- Petroleum Services Association of Canada
- Shell Canada Ltd.

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Process

- Drilling Innovators Advisory Group
- Publicly available drilling data 2000-2004
- Selection and vetting of representative fields
- Looked at WCSB as six discrete regions
- Data collection from 12 operators working in 35 fields
- Selected interviews to gain context & understanding:
  - Operators
  - Drilling contractors
  - Technology providers
  - Stakeholders

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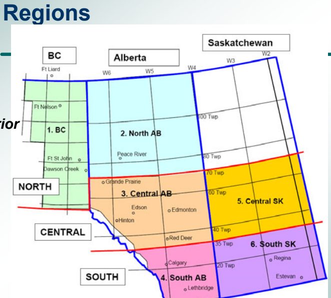
Regions

NORTH: Not load leveled, drilling performance inferior



SOUTH: Load leveled, drilling performance superior

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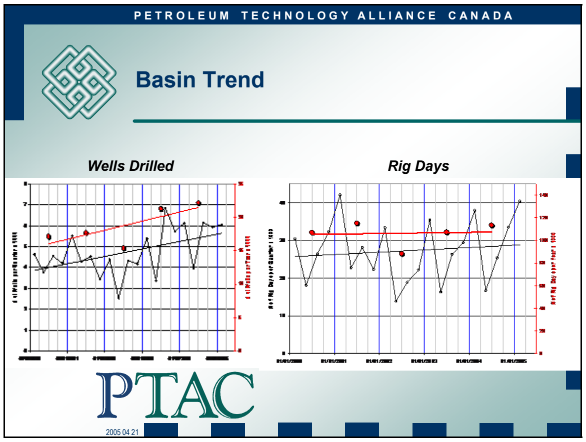
PETROLEUM TECHNOLOGY ALLIANCE CANADA
Basin Trend
Wells Drilled
Rig Days
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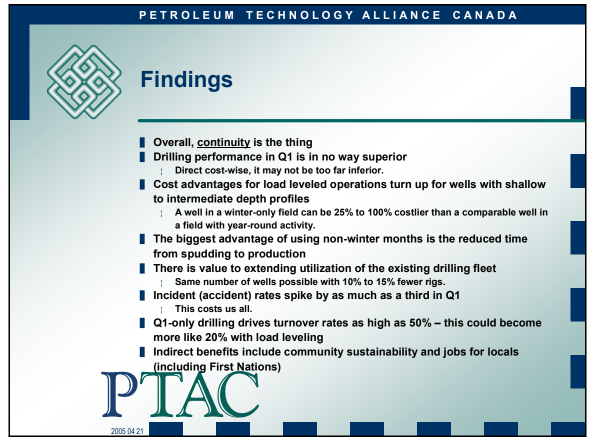
PETROLEUM TECHNOLOGY ALLIANCE CANADA
Findings
Overall, continuity is the thing
Drilling performance in Q1 is in no way superior
Direct cost-wise, it may not be too far inferior.
Cost advantages for load leveled operations turn up for wells with shallow to intermediate depth profiles
A well in a winter-only field can be 25% to 100% costlier than a comparable well in a field with year-round activity.
The biggest advantage of using non-winter months is the reduced time from spudding to production
There is value to extending utilization of the existing drilling fleet
Same number of wells possible with 10% to 15% fewer rigs.
Incident (accident) rates spike by as much as a third in Q1
This costs us all.
Q1-only drilling drives turnover rates as high as 50% – this could become more like 20% with load leveling
Indirect benefits include community sustainability and jobs for locals (including First Nations)
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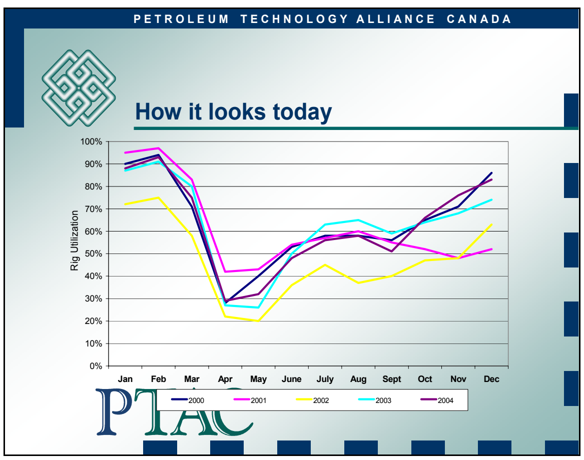
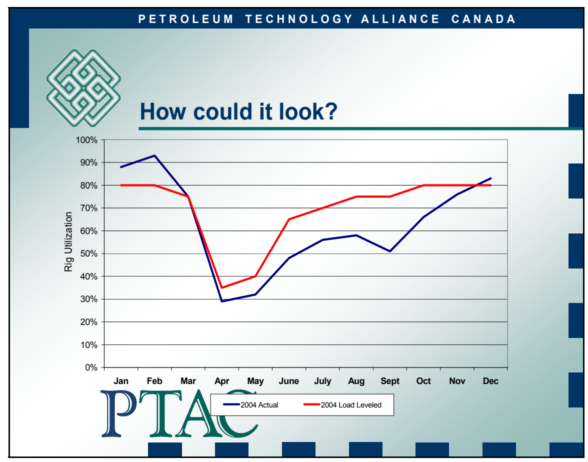
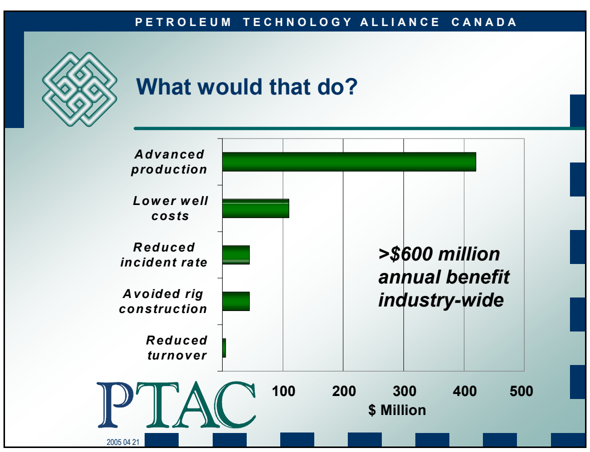
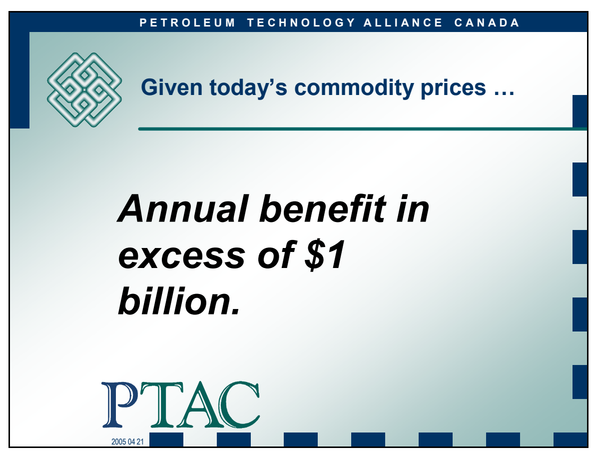

PETROLEUM TECHNOLOGY ALLIANCE CANADA
How it looks today
Rig Utilization
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Jan Feb Mar Apr May June July Aug Sept Oct Nov Dec
2000
2001
2002
2003
2004
PTAC


PETROLEUM TECHNOLOGY ALLIANCE CANADA
How could it look?
Rig Utilization
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Jan Feb Mar Apr May June July Aug Sept Oct Nov Dec
2004 Actual
2004 Load Leveled
PTAC


PETROLEUM TECHNOLOGY ALLIANCE CANADA
What would that do?
Advanced production
Lower well costs
Reduced incident rate
Avoided rig construction
Reduced turnover
>$600 million annual benefit industry-wide
100 200 300 400 500
$ Million
PTAC
2005 04 21


PETROLEUM TECHNOLOGY ALLIANCE CANADA
Given today's commodity prices …
Annual benefit in excess of $1 billion.
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Release

Going to print Sept. 30

Innovative Drilling Technologies & Best Practices Forum Oct. 18

Media release Oct. 10

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PETROLEUM TECHNOLOGY ALLIANCE CANADA

Innovative Drilling Technologies and Best Practices Forum

Date: Tuesday, October 18, 2005
Time: 11:30 a.m. – 4:00 p.m. (Registration at 11:00 a.m.)
Location: ConocoPhillips Theatre

- The day will begin with lunch followed by the release of the results from *Level Best: Drilling Seasonal Load Leveling Business Case* report. The rest of the afternoon will consist of 20-minute presentations spanning policy and new technology followed by Q&A panels. The forum will end with an open floor discussion.

FEE SCHEDULE	
PTAC Member	$195 CDN (plus GST)
Sponsor Members	$265 CDN (plus GST))
Others	$335 CDN (plus GST)
Full-time Students	$ 65 CDN (plus GST)

Costs include presentation materials, breaks and lunch.

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Innovative Drilling Technologies and Best Practices Forum (cont'd)

Opportunities

- Access the final results of the PTAC Drilling Seasonal Load Leveling Business Case Project
- Hear from the B.C. government on policy and regulations influencing future oil and gas industry seasonal load leveling incentives
- Learn from industry leader case studies about new technologies and business processes that help to spread drilling activity throughout the year and subsequently improve profitability
- Participate in a highly focused poster session as a supplier or user of load leveling technology
- Participate in roundtable discussions on barriers and needs for future oil and gas industry performance improvement through development and application of load leveling technology and alternative ways to program drilling activity

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PETROLEUM TECHNOLOGY ALLIANCE CANADA

PTAC Contact Information for the Innovative Drilling Technologies and Best Practices Case Study and Forum

Eryn Rizzoli
Innovation and Technology Coordinator
Petroleum Technology Alliance Canada
T: 403-218-7708
F: 403-920-0054
E: erizzoli@ptac.org
www.ptac.org/drl/drlf.html

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APPENDIX E – Interview Guides

Interviews with operators using mats:

Please provide an idea of the areas within the WCSB that your company is using mats, and to what extent. How has your company's use of mats changed over the past few years?

What applications have you found mats to be most suitable for
(terrain, season, distance to well site, etc.)?

What are the biggest benefits to using mats?

What are the biggest drawbacks to using mats?

Has using mats required any/significant changes to your drilling operations?

How financially viable it is to use mats?

Any less-than-successful stories about using mats?

Other technologies or products that are used with mats to help with non-winter drilling?

Interviews with companies operating in B.C.:

Which B.C. programs has your company participated in (i.e. credit roads, royalty programs, etc.)?

Have these programs helped to influence your company's drilling activities? How?

In your company's experience, has the permitting process in B.C. become more efficient in recent years? Does your company experience constraints in this area?

Does your company face environmental restrictions (forest, wildlife, etc.) in its B.C. drilling activities?

Ideas for other incentives that you would find valuable?

Any other comments regarding your company's operations in B.C. are welcome.

APPENDIX F – Data Analysis Overview

Data Source

- Nickle's DOB
- All wells deeper than 2000m
- Period : 2000-01-01 to 2004-12-31 (Rig Release Date)

Raw Data

- For each well, the DOB provided the following data :
  - WellName, AreaID, LicenceID, WellClass,WellType, WellStatus, SpudDate, RigReleaseDate, StatusDepth, ProjectedDepth, LocationLine, LegalSub, Section, Township, Range, Meridian, Quarter, Centizone, ZoneBlock, MapUnit, MapUnitSub, MapSheet, RigName, PowerCode, DrillingCapacity
- Spud date and Rig Release Dates are to the nearest day.

Calculated Data

- For each well, the following parameters were calculated :
  - Rig Days = rig release date-spud date
  - Drilling Efficiency (see below) = status depth / rig days

Drilling "Performance"

- In order to compare wells, a simple drilling "Performance Indicator" is used :
  - "Drilling Efficiency" m/d = total meters drilled / total days, spud to rig release
- Performance in m/d is only accurate for reasonably deep wells (+/- > 2000m).
- The data are to the nearest day, so for shallower, shorter duration wells (less than 7-8 days), data to the nearest day do not provide enough precision to allow comparisons between specific wells, but do give insight into general trends for large numbers of wells.
- M/d can be used as a "performance indicator" since most drilling costs are based on daily rates so "shorter = lower cost."
- Horizontal Wells: the data give well depth, not how much hole was drilled; m/d based on well depth is not a valid performance measure.
- Quarterly Averages were calculated by summing the total meters drilled and dividing by the sum of the total rig days, for example :
  - 1st Quarter 2003, Wells under 950m:
    451,725 total meters drilled / 1,851 total rig days =
    244 m/d Average Drilling Efficiency

Quarterly Variation

- Data grouped by yearly quarter provide a good approximation of physical drilling seasons :
  - 1st Quarter (January, February, March): winter, frozen ground, high activity.
  - 2nd Quarter (April, May, June): spring break-up, road bans, very low activity.
  - 3rd Quarter (July, August, September): summer, poor access to wetland areas.
  - 4th Quarter (October, November, December): fall, wetlands freezing; freeze timing can vary and seems to be later in recent years = shorter winter drilling season).
- The well data were plotted against rig release date, so the data associated with a quarter are for all wells that rig released in that quarter.