ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

PUBLIC INQUIRY
OPERATIONAL REVIEW OF THE
SHELL CARBONDALE PIPELINE SYSTEM
LICENCE 23800
WATERTON FIELD **Decision 99-24**
SHELL CANADA LIMITED **Proceeding No. 980058**

1 INTRODUCTION

1.1 Background

In March 1995, the Alberta Energy and Utilities Board (EUB) issued Decision 95-6, approving Shell Canada's application to construct a steel pipeline (the Carbondale system), 32 kilometres (km) in length from wells located in the upper Carbondale River area of southwest Alberta to connector pipelines supplying the Shell Waterton Gas Plant. The pipeline was designed to carry sour natural gas with a maximum H_2S content of 320 moles/kilomole (32 per cent). Figures 1 and 2 show the general location of the pipeline and other relevant geographic points of interest to this inquiry.

The Carbondale system was commissioned in September 1995, tying in three wells located at Legal Subdivision 7, Section 20, Township 6, Range 3, West of the 5th Meridian (7-20 well); Legal Subdivision 12, Section 9, Township 6, Range 3, West of the 5th Meridian (12-9 well); and Legal Subdivision 6, Section 12, Township 6, Range 3, West of the 5th Meridian (6-12 well). Line 45 (4-inch, or 114.3 mm) receives production from the 7-20 well and carries it to the 12-9 well tie-in. From there, line 46 (6-inch, or 168.3 mm) carries the combined production of the 7-20 and 12-9 wells to the 6-12 well tie-in. From there, line 53 (6-inch) carries the combined production from all three wells to Junction J, located at Legal Subdivision 1, Section 7, Township 6, Range 2, West of the 5th Meridian (Junction J). From Junction J, line 42 (8-inch, or 219.1 mm) carries production towards the Shell Waterton Gas Plant.

Junction J also includes a crossover to the Shell North End system, which consists of a 4-inch line carrying the production from two additional Shell wells, one at Legal Subdivision 5, Section 20, Township 6, Range 2, West of the 5th Meridian (5-20 well) and the other at Legal Subdivision 6, Section 17, Township 6, Range 2, West of the 5th Meridian (6-17 well), to Junction J. This 4-inch pipeline continues past Junction J parallel to line 42 southwards towards the Waterton Gas Plant. Pigging facilities for the 6-inch and 8-inch lines (lines 53 and 42), a line heater, and the flare system are located at Junction J.

The production from the 5-20 and 6-17 wells in the Shell North End system crosses the property of local residents, Dr. David and Mrs. Jean Sheppard (the Sheppards), via a pipeline right-of-way located approximately 200 metres (m) from their residence. Junction J is located approximately 350 m southwest of their residence. Line 42 crosses across the southwest corner of the Sheppards' property on its way to Junction K and continues south, passing within approximately 200 m of the residence of Mr. Mike Judd. Mr. Judd's residence is approximately 600 m south of Junction J.

On 18 December 1995, after only a few months service, a failure on line 42 was detected approximately 600 m downstream of Junction J at 13-5-6-2W5. It was later determined that a perforation in the pipeline about 3 millimetres (mm) in diameter had been caused by internal corrosion. The pipelines upstream and downstream of Junction J were shut in pending investigation and repairs. Mr. Judd and the Sheppards requested a public hearing to investigate the circumstances of the pipeline leak. The EUB agreed to hold a hearing and, in the interim, on 2 May 1996 allowed gas to be transported through lines 45, 46, and 53 to the existing 4-inch pipeline that parallelled the failed line 42. The hearing was subsequently cancelled after the two parties withdrew their objections to the recommissioning of line 42. After the review of Shell's failure reports and its commitments to certain operational procedures, the Board authorized the return to service of line 42 on 19 July 1996.

After the various wells and pipelines associated with the Carbondale system were returned to operation, further operational problems were encountered and remedial procedures were carried out on some of the wells. Internal inspection tools and external monitoring also identified ongoing pipeline corrosion, and a program of repairs and replacements was carried out during a period of about one year. On 18 August 1997, as lines 45 and 46 were being removed from service to evaluate indications of corrosion, a failure was discovered on line 46. Ms. Pearl Barbero, a local rancher, noted the odour of sour gas and found a dead cow and calf near the pipeline, approximately 5 km upstream of Junction J. The 6-12 well was then shut in and line 53 was also removed from service.

An investigation revealed that the 18 August 1997 failure occurred at a girth weld on a portion of the pipeline that had been cut out and replaced during June and July 1997, as part of ongoing pipeline repairs and replacements. Shell conducted investigation, reporting, and repair work on the failure from 18 August to December 1997. The investigation determined that the second failure resulted from sulphide stress cracking of the weld.

After the second failure, the EUB received requests from the Sheppards and Mr. Judd to suspend the operation of the entire Carbondale system and conduct a public inquiry into its operation. The residents stated that they were concerned about the integrity of the pipeline and the potential impact of ongoing operations on their safety and health. Shell objected to the request of the landowners for such a public inquiry and instead proposed a meeting between the residents and Shell senior operations personnel. The residents, however, rejected this proposal.

The Board derives its authority to conduct inquiries under several provisions of its enabling legislation, particularly Section 22 of the Energy Resources Conservation Act and Sections 5 and 29 of the Pipeline Act. Inquiries may be conducted into broad, industry-wide policy issues or focus on the specific operations of a single licensee. In the latter case, the Board may direct operators to effect changes to its operations or facilities, based on the inquiry findings, to ensure that facilities are operated and maintained in a safe manner without undue risk to public health and the environment. Sections 21 and 34 of the Pipeline Act illustrate the Board's authority under a regulatory scheme that recognizes the safety of facilities as a primary objective.

The EUB determined that a public inquiry into the operation of the Carbondale system was warranted and, by letter dated 19 February 1998, informed the interested parties of its decision. At the same time, the EUB authorized Shell to recommission lines 45 and 46, subject to certain operational conditions, in order to obtain additional operational data prior to the public inquiry.

By letter dated 28 March 1998, Mr. Judd applied to the EUB for a hearing, under Section 43(1) of the Energy Resources Conservation Act, to have the EUB reconsider and rescind its decision to allow lines 45 and 46 to return to service prior to holding the public inquiry. The Sheppards supported Mr. Judd's application. The parties subsequently agreed to argue the merits of the application based on the evidence available to the EUB as of February 1998, and the hearing was held on 1 June 1998.

On 17 September 1998, the EUB issued Decision 98-16, confirming that it was satisfied that its original decision to allow the two pipelines to return to service was appropriate. In that decision, the Board stated that it felt that the operational conditions currently being followed by Shell would ensure the safe operation of the pipelines and that valuable operational information would be gained by continued operation during the period prior to the public inquiry.

1.2 Inquiry

The Board issued its Notice of Public Inquiry into the Operational Review of the Carbondale Pipeline System on 22 December 1998. In response to requests from the intervening parties for more information, the Board directed Shell to provide or make available certain information for perusal by the interveners. In response to requests for more preparation time, the proceeding was rescheduled to 30 March 1999, with a Notice of Rescheduling issued on 4 February 1999.

Mr. Judd advised the Board by letter on 29 March 1999, the day before the public inquiry convened, that he was no longer prepared to participate.

On 30 March 1999, the Board, consisting of Presiding Board Member F. J. Mink, P.Eng., Board Member Dr. B. Bietz, P.Biol., and Acting Board Member K. G. Sharp, P.Eng., commenced the proceeding.

THOSE WHO APPEARED AT THE INQUIRY

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited	
Mr. S. Denstedt	Mr. I. Kilgour, B.Eng
Mr. B. Gilmour	Mr. A.Hart, B.Sc
Ms. JoAnn Jamieson	Mr. K. Welte, B.Eng.
	Mr. K. Goertz, P.Eng.
	Dr. K. Szklarz
	Dr. R. Holmes-Smith
	Mr. K. Johnson, P. Eng.
	Dr. D. Leahey
	Dr. D. Davies
	Mr. G. Mulzet
	Mr. R. Howorko
	Mr. N. Bich, M.Sc.
Dr. D. Sheppard and J. Sheppard (the Sheppards)	
Mr. G. Fitch	Dr. D. Sheppard
	Mrs. J. Sheppard
	Mr. M. Byrne
	Mr. M. Kuppe, B.Sc.
	Mr. C. Duncan, P.Eng
	Mr. E. New, R.E.T.
Alberta Energy and Utilities Board (EUB) staff	
Mr. D. Larder, Board Counsel	
Mr. S. Lee, P.Eng.	
Mr. D. Grzyb, R.E.T.	

The hearing was completed on 23 April 1999. On 3 September 1999, Mr. Frank Mink withdrew from the proceedings.

2 ISSUES

In submissions from the parties prior to the inquiry and during the proceedings, several recurring themes became evident as primary to understanding the operation of the Carbondale system. These themes are summarized as follows and will be addressed in the following sections:

- Corrosion – Is the corrosion control program for the Carbondale system successful?
- Integrity – Can the integrity of Carbondale system be preserved into the future?
- Impact – What are the effects of the Carbondale system's operations on the health and well-being of local residents?
- Communication and Community Relations – What has been the relationship between the company and the community?

2.1 Corrosion – Is the corrosion control program for the Carbondale system successful?

2.1.1 Views of Shell

Shell explained how, prior to starting up the 7-20 and 12-9 wells in September 1995, it had anticipated the start-up conditions based on its prior experience with similar wells in the region. Shell stated that it had used that experience to design a corresponding initial corrosion protection plan for the Carbondale system. This included pre-start-up batch inhibition treatment, continuous inhibitor injection at the wells, installation of corrosion coupons and probes at selected locations, and a fluid sampling and analysis program. Internal pipeline corrosion inspection tool (IPCIT) inspections of the pipeline were scheduled based on an assumed corrosion rate of 4 mm per year, which was derived from Shell's proprietary in-house corrosion model. Shell stated that it had planned to add additional pigging and batching to its program if required upon review of the coupon and probe data.

Shell stated that operating conditions at the wells changed shortly after start-up, with rapidly declining flow rates resulting from sulphur deposition in the wellbore. This necessitated the unplanned shut-in of the wells for downhole treatment of the sulphur deposition. Shell explained that it was in the process of evaluating the significance of this development when, shortly after restarting the wells, the corrosion perforation occurred on the 8-inch pipeline downstream of Junction J. Shell believed the primary corrosion damage to the 6- and 8-inch pipelines occurred within the very short (four-day) period between the initial commissioning and the first batch inhibition treatment of the pipelines.

Once the wells were stimulated and restarted, the corrosion control program was revised to add monthly batching and biweekly pigging. Subsequent IPCIT runs showed that, despite these additional measures, corrosion was still occurring, particularly on the 6-inch pipeline, and further repairs became necessary.

Shell stated that it expended considerable effort to gain an understanding of the corrosion mechanisms experienced in the Carbondale system and to implement a properly configured mitigation program to control the corrosion. Shell stated that at its most thorough stage, the corrosion mitigation program had been very rigorous, including well-site separation, continuous inhibition, weekly batch inhibition, continuous injection of sulfur solvent at the 12-9 well, and weekly pigging to remove chlorides and deposited solids. In addition to the IPCIT runs, Shell employed bell-hole monitoring, corrosion probes and coupons, analysis for inhibitor residuals, and water sampling in order to determine corrosion rates. Shell noted that based on the success of this program and its belief that corrosion rates in the pipeline had stabilized, it had decided to reduce the intensity of the mitigation program in November 1998.

Based on research that it had performed following the failures, Shell concluded that it had initially not fully understood the synergistic impact of the combination of high-chloride water, elemental sulphur production, and low flow rates in the presence of sour gas when it began to operate the Carbondale system. Laboratory testing showed that, in particular, increasing the chloride content of fluids from 1000 parts per million (ppm) to 100 000 ppm caused the pitting rate to increase by as much as four times, to about 36 mm per year. Shell's original corrosion model did not incorporate this knowledge and therefore significantly underestimated the corrosion rate.

Shell disagreed with the interveners' suggestion that prior pipeline failures at Shell's Caroline, Burnt Timber, and Jumping Pound facilities had been caused by similar corrosion mechanisms and should have served as a warning at Carbondale. Shell stated that since determining the new mechanism, it had shared this information with certain industry members directly and with others through presentations at corrosion conferences.

Shell stated that its current corrosion monitoring program was very conservative. For example, in order to determine the appropriate scheduling of IPCIT inspections, Shell stated that it used a planning corrosion rate of 6 mm per year for the 6-inch pipeline and 3 mm per year for the 8-inch pipeline. Since these planning rates were much higher than the rates Shell believed currently existed, this was expected to result in conservatism in the calculations and ensure that the inspections would detect any further significant corrosion growth before it reached dangerous levels.

Shell noted that it is currently following a replacement program on the Carbondale system whereby any pipe that contains pits identified by IPCIT runs as having greater than 35 per cent pipe wall loss is exposed for confirmation. If the pit is isolated (i.e., is not clustered with other pits), an appropriate future cutout time, consistent with other pipeline operations, is scheduled. If the pit is not isolated, the damaged joint is removed as soon as possible.

In response to questioning, Shell also observed that it did not design sour gas pipelines using a corrosion allowance, as that is only appropriate to instances where general metal loss would be expected. In corrosive situations such as at Carbondale, Shell believed that pitting mechanisms must be controlled through a proper mitigation program.

Shell noted that the IPCIT runs indicated that the application of its modified corrosion control program had reduced the corrosion rates to low levels. Shell provided a statistical analysis that it believed indicated an annual corrosion rate of less than 0.2 mm per year, significantly less than originally experienced. Shell also argued that it was possible to protect previously damaged pipe, as well as new pipe, from further corrosion, and that Shell's IPCIT data confirmed this.

As a result of the high number of IPCIT runs performed on the Carbondale system, Shell stated that it was confident that it had fully assessed the entire pipeline and that it was receiving repeatable results. Shell believed that the IPCIT runs indicated that the maximum pit depths had stabilized at less than 35 per cent of wall loss and were not increasing. Shell stated that due to increased flow rates, frequent pigging, and the use of sulphur solvent, the Carbondale system was now clean and the tool passed through the pipeline without showing any evidence of remaining solids. Although some of the inspection runs reported by Shell experienced times when the tool travelled outside its recommended speed range, Shell explained that useful data still had been captured and could be used with proper interpretation. Through operational experience, Shell believed that it had developed excellent velocity control of the inspection tool.

Shell stated that the causes of the second leak on the Carbondale system, which had resulted from a sudden weld failure, were not related to the causes of the first leak. Through its subsequent investigation, Shell stated that it had determined that the second failure was due to a combination of factors resulting from conditions of high residual stress, a hardened weld due to quenching, and the presence of a weld defect. To prevent similar occurrences, Shell noted that it had instituted several preventative procedures. These involved minimum specifications for the setting of mud plugs during repairs and stricter quality assurance for welding procedures and contractors. Shell's revised procedures also required a minimum 4 m pipe length for replacement sections and the exposure of a minimum of 4 m of free pipe on either side of the cut to minimize inducing additional stresses as a result of repairs. Shell stated that it had endeavoured to share its experience with other industry members through presentations at technical conferences.

2.1.2 Views of the Interveners

The interveners stated that, in their view, the corrosion control program developed by Shell for the operation of the Carbondale system was inadequate and improper from the outset. Their witnesses stated that they believed that Shell was imprudent in establishing its initial corrosion control program based on assumed operating parameters. In their view, Shell should have assumed worst-case scenarios and started the system with an "overkill" corrosion control program. Later it could have scaled back corrosion prevention activities if they were proven to be unnecessary. By adopting such an approach, they argued, much of the existing damage to the Carbondale system may have been avoided, and the corrosion leak could have been prevented.

The interveners also questioned whether Shell had acted quickly enough to evaluate and adjust its corrosion control program when production rates began declining shortly after commissioning of the pipeline. They felt that Shell had not responded to the indications from the monitoring probes and declining production rates in a timely fashion.

The interveners acknowledged the findings of Shell's research into the weld failure. However, they noted that while Shell's re-evaluation of the pipeline welds indicated that all remaining welds met the Canadian Standards Association Z662-96, *Oil and Gas Pipeline Systems* (CSA Standard) requirements for sour service, some welds did not meet all the requirements of Shell's own standard. The interveners questioned why Shell chose to not replace those welds, as required by its own standard, and presented this as an example of Shell's lack of conservatism towards safety.

The interveners contended that Shell's determination of present corrosion rates was at best an estimate, as the rates were statistically manipulated and could therefore be altered substantially both by the selective choice of data and application of various statistical procedures. They also noted that the rate as presented by Shell was in disagreement with, and was much less than, rates communicated to the Board in recent progress reports. They believed that Shell had included some "negative" corrosion rate readings in the calculation of the average corrosion rates. Since such negative rates were obviously not possible, they believed that this inclusion artificially reduced Shell's average corrosion rates. They also noted some inconsistencies within Shell's own presentation of corrosion rates and suggested that Shell could not be sure of its calculated corrosion rates.

The interveners further noted that Shell's reported current corrosion rates were calculated after six months of their "best effort" corrosion control program. They suggested that Shell's supplied data indicated that a more reasonable assumption of a corrosion rate for the 6-inch pipeline would be 0.8-1.0 mm per year, based on the most frequent measurements found in the data. The interveners pointed out that the use of average corrosion rates and inclusion of negative corrosion rates could not be perceived as being a conservative approach.

The interveners pointed out that Shell's calculation of corrosion rates also relied heavily on the measured values of the corrosion pits supplied by the IPCIT equipment. They argued that the IPCIT data were known to be inaccurate to some degree and provided an unreliable measure of the corrosion that might be continuing within already established pits. The accuracy of the IPCIT tool was also called into question, as it was acknowledged to have at times run either faster or slower than its optimum speed. The interveners also questioned the ability of the tool to identify narrow, deep pits when these occurred as part of an area of longer, shallower pits, as well as its ability to accurately measure narrow, deep pits, since it was calibrated for longer, shallower pits.

The interveners also noted inconsistencies in Shell's presentation material regarding cutout criteria. They questioned if Shell had reliable record keeping regarding its cutout criteria and control over operating issues. The interveners expressed significant concern that, notwithstanding the fact that an inquiry into the Carbondale system was to be held, Shell had chosen to dispose of cutout pipeline sections it had been holding in storage. These, they argued, would have been very valuable in assessing the correlation between the IPCIT-measured and actual pit dimensions.

The interveners contended that Shell, as an experienced operator of sour gas facilities and pipelines in Alberta, should have been fully aware of the likelihood of corrosion problems in the Carbondale system. They argued that the synergistic effects of elemental sulphur production should have been known to Shell, and they described several instances where they believed Shell had encountered similar corrosive situations in other Shell pipelines in the recent past. They maintained that Shell should have been able to learn from these other failures, update its corrosion models, and subsequently predict the possible occurrence of similar problems in the Carbondale system, but had not adequately done so.

2.1.3 Views of the Board

The Board believes that the first issue that must be addressed is whether the events that led to the initial failure of the Carbondale system are sufficiently well understood that the risk of a similar event in either the Carbondale system or any other Alberta sour gas pipeline can be adequately controlled.

Based on the evidence presented by Shell, it is apparent that the operating conditions that developed initially within the Carbondale system were not anticipated, nor were the extremely rapid rates of corrosion. Shell's original corrosion control program — which included a pre-start-up batch inhibition treatment, continuous inhibitor injection at the well, installation of corrosion coupons and probes at selected locations, and a fluid sampling and analysis program — was clearly inadequate to protect the pipe or detect the rates of corrosion that occurred. Furthermore, the assumed corrosion rate of 4 mm per year, as derived from Shell's corrosion model, clearly caused Shell to underestimate the appropriate frequency of IPCIT inspections and appropriate batching and pigging schedules.

Whether Shell should have been expected to have predicted the actual corrosion rates that occurred in the Carbondale system and to have taken additional measures to reduce the risk of failure is less clear from the evidence. What is important is whether the conditions that created the unexpectedly high levels of corrosion are now properly and thoroughly understood.

The Board notes that the model Shell is currently proposing to explain the corrosion mechanisms was not questioned at the inquiry. The Board is satisfied that a combination of high chlorides, the presence of elemental sulphur, and high depositional rates due to low gas velocities led to the initial failure of the pipeline and that this mechanism is now adequately understood. The Board believes that Shell has also made reasonable efforts to communicate the results of its research into the failure mechanism to the sour gas industry and that other operators should now be aware of any associated risks.

The Board also accepts that the second failure was a result of inadequate engineering and construction practices that occurred during the replacement of a repaired pipeline section and was not a direct result of the above corrosion mechanism. The Board believes that Shell has instituted sufficient procedural modifications to prevent the occurrence of a similar event. The Board is also satisfied that all remaining welds have been shown to meet the requirements of the CSA Standard for sour service.

With regard to the program implemented by Shell to control corrosion in the pipeline following the initial failure, the Board believes that there is sufficient evidence to confirm a significant decrease in the corrosion rates. However, the Board is less convinced that the current corrosion rates are as low as predicted by Shell. The Board notes the difficulty of accurately measuring complex pitting structures, even with relatively sophisticated IPCIT tools. The Board also notes that Shell was required on various occasions to extrapolate IPCIT data that were not captured within the design parameters for the tool. The Board also has concerns about the inclusion of "negative" values in the calculation of average corrosion rates, as well as the general statistical approach used by Shell. In the Board's view, the approach used did not well match Shell's claims of the consistent use of a conservative engineering approach. The Board also notes that it would have been potentially very useful to have been able to examine the various removed pipe segments in order to verify the IPCIT-measured corrosion values against actual measurements. Shell's disposal of the cutout pipe from the Carbondale system while an inquiry was pending was inappropriate.

Although not discussed at the inquiry, the Board notes that many operators are currently opting to test new wells either directly to pipeline or to pipeline after only limited open hole testing. This is often done in order to reduce the need for flaring and the associated environmental impacts. In doing so, there is obviously an increased risk that actual corrosive conditions may differ substantially from the predicted normal operating conditions. This in turn may result in an elevated level of pipeline corrosion and risk of pipeline failure. This is not dissimilar to the conditions that Shell observed in the Carbondale system.

It is not in the public interest to trade off the reduction in flaring that can be achieved by testing directly to pipeline if the risk of pipeline failures is increased significantly as a result. The Board expects all operators to take this risk into account and incorporate the appropriate initial safety procedures when designing their initial corrosion control programs for such cases. Only after a company has had a reasonable amount of operating history should the initial programs be modified to better reflect the observed conditions.

The Board does not believe that the reliance upon a corrosion allowance for the protection of a sour gas pipeline is an appropriate manner of operation in situations where internal pitting may be expected, and therefore it would not have been an appropriate manner of control in this case. The Board also accepts the desire and business need for Shell to optimize its corrosion control program and reduce unnecessary costs when it becomes prudent to do so. However, the Board does not believe that Shell has established a sufficient history of successful long-term control of corrosion in the Carbondale system. Therefore the Board does not accept the submission that it is prudent to reduce the corrosion control program at this time. This issue is discussed further in the following section.

2.2 Integrity – Can the integrity of the Carbondale system be preserved into the future?

2.2.1 Views of Shell

Shell submitted that in order to evaluate the integrity of the Carbondale system, it followed a very conservative engineering assessment approach that fully complied with the requirements of the CSA Standard.

Shell stated that clause 10.8.1.6 of the CSA Standard allowed for two options in evaluating pipelines that contained defects. One option required repairs as per the requirements of clauses 10.8.2 to 10.8.6 inclusive, while the second allowed for the application of an engineering assessment to determine the allowable operating pressure of the damaged pipeline. With regard to the first option, Shell noted that clauses 10.8.2 to 10.8.6 allow for corrosion imperfections, regardless of length, of up to 10 per cent of nominal wall thickness. For corrosion imperfections of 10 to 80 per cent wall loss, the CSA Standard uses a calculated assessment of allowable corroded length. However, this does not include operating conditions such as pressure, which Shell considered to be very conservative.

Shell indicated that it chose instead to apply the option of conducting an engineering assessment, noting that the CSA Standard did not specify which engineering calculation method was appropriate. Shell stated that its engineering assessment approach was based on a comprehensive understanding of the potential failure mode and the safety margin that existed between normal operating conditions and the expected failure condition.

Shell confirmed that it used a commercial defect assessment model called RSTRENG (acronym for Remaining Strength) to estimate the failure strength of the pipe. Shell explained that RSTRENG was a modified version of the American Society of Mechanical Engineers/American National Standards Institute ASME B31G-1991 *Manual for Determining the Remaining Strength of Corroded Pipelines* (B31G) methodology and was generally accepted by industry to estimate the burst strength of locally thinned areas in pipelines.

Shell stated that both B31G and RSTRENG assumed that more metal was lost beneath random pitting than would actually occur in practice. Shell considered that B31G was overly conservative for imperfections containing longer linked pits, because it used a rectangular (groove) assumption of metal loss in its failure estimates, rather than the parabolic assumption used in RSTRENG. This would result in the repair or replacement of more pipe than was necessary to maintain adequate integrity. While both methods employed a parabolic assumption of metal loss for short linked pits, such as those found in the Carbondale system, Shell considered its RSTRENG analysis to be even more conservative than the B31G analysis. They explained that because pits initiated randomly and grew at different rates, long pits were not necessarily associated with the deepest pits. As a result, it would be extremely unlikely that a long link of pits would be both uniformly deep and sufficiently long to place the pipeline in jeopardy of a burst failure. Further, Shell also believed that the recent operating history of the pipeline demonstrated that the corrosion rates for pit depths exceeding 30 per cent wall loss was very low. Using RSTRENG, Shell estimated that failure would not occur in locally thinned areas of up to 55 per cent wall loss for linked pitting lengths of less than 5 m.

Shell stated that by adopting the engineering assessment approach, it was able to ensure that an adequate safety margin existed, as the calculations considered the operating pressure and the actual defects in the pipeline. Shell stated that it first used B31G and RSTRENG to establish conservative failure limits using a safety factor of 1, as required by the B31G and RSTRENG methods. Then, by considering the results of IPCIT inspection with physical verification, and by also applying a safety margin to the calculated failure limit, Shell selected the cutout criteria for pits. Shell estimated that a cutout criterion of 35 per cent wall loss would represent approximately a 40 per cent safety margin, based on its longest verified linked pit length of 250 mm.

Shell stated that it had assessed the method developed by British Gas Technology (BG Technology) for evaluating the burst strength of corroded pipe, which had been discussed by the interveners. Shell agreed with the interveners that the BG Technology method was the most current and accurate approach for performing a corroded pipeline assessment. By using that method and applying Shell’s current cutout criterion, Shell determined that its safety margin would be 45 per cent when based on a comparison between calculated failure pressure and maximum operating pressure.

In response to questions, Shell stated that because of its rigorous approach and its experience and knowledge of the operation of the Carbondale system, it believed that its engineering assessment approach and the 35 per cent cutout criterion was more conservative than most industry practice. Shell argued that its assessment approach would ensure no yield or pitting-related failure would occur.

In response to questioning regarding the safety margin of its assessment, Shell said that it considered the 0.72 (B31G) or 0.60 (EUB/sour gas) design factors to be applicable for the construction of a new system rather than for an existing system. Shell stated that it believed that these design factors were intended to consider the future degradation of the system and any unforeseen circumstances that could arise. Shell accepted, under questioning, that cutout criteria using the 0.72 and 0.6 safety factors would occur at about 35 and 25 per cent wall loss respectively. However, Shell stated that it chose the 35 per cent criterion because Shell considered 0.72 to be an appropriate safety factor, taking into consideration the operating pressure and its monitoring and inspection program.

With regard to the operation of the Carbondale system, Shell stated that it had adopted and would continue to apply the following approach to ensure integrity:

- All corrosion indications greater than 30 per cent depth would be rigorously assessed.

- All corrosion indications showing 35-50 per cent depth would be excavated for verification and to confirm the IPCIT tool measurements. Shell stated that although IPCIT could have an uncertainty of up to 10 per cent, it would still have a sufficient margin of safety to ensure that there would be no failure. If pits were isolated (i.e., not linked), an appropriate cutout time would be scheduled. If pits were found not to be isolated (i.e., linked), they would be removed immediately.

- All sections with corrosion indications greater than 50 per cent depth, regardless of length, would be immediately cut out and removed.

- IPCIT frequencies would be scheduled by applying a maximum corrosion rate to the deepest pit and calculating half the time for the pit to grow to an 80 per cent depth. Currently the corrosion rates used were 6 mm per year for the 6-inch pipeline and 3 mm per year for the 8-inch pipeline, which would result in IPCIT frequencies of about three months and six months respectively. Shell stated that these planning corrosion rates were much higher, and therefore more conservative, than the maximum observed corrosion rates.

At the inquiry, Shell noted that through the period running from about May through October 1998, it began to make efforts to optimize its corrosion control program in order to reduce both unnecessary costs and activity level. Shell stated that once it was established that the chloride levels in the production were stabilized to below 1000 ppm, the well-site water separation facilities were removed. Batch inhibitor frequency was decreased from weekly to monthly treatments, which also reduced flaring activities at Junction J. Weekly pigging was continued but changed from wire brush pigs to plastic pigs. Sulphur solvent injection rates were adjusted to better match observed levels of undissolved sulphur in the pipeline. The frequencies of IPCIT inspections were also reduced commensurate with the observed reductions in corrosion rate. Batch inhibition treatment immediately after downhole DMDS (dimethyl disulphide) treatment was discontinued.

Shell noted that it had also been experiencing operational difficulties in the Waterton Complex due to fouling that was attributed to the inhibitor composition. After thoroughly evaluating candidates through laboratory testing, Shell stated that it had recently changed the type of batch inhibitor and was confident that the new inhibitor would provide satisfactory performance.

Shell indicated that the program changes it had made in recent months would result in substantive cost savings, as well as reducing some of the intense activity surrounding the operation of the pipeline. Shell explained that the changes were subject to very strict change control procedures and that such changes are thoroughly reviewed and subject to engineering scrutiny before being implemented. Shell also noted that it was operating the Carbondale system at higher velocities than during the initial operation. This, Shell argued, would further reduce the risk of corrosion by reducing the deposition rates of solids and water. Shell confirmed, when questioned, that the Carbondale system would remain financially viable regardless of whether the previous full corrosion program or the present optimized corrosion program were implemented.

At the inquiry, the possibility of installing a corrosion-resistant liner into the Carbondale pipeline was discussed. Shell stated that although it had sometimes used polymer liners in the past, they too were not without operational difficulties and Shell had experienced failures of liners as well. Internal Shell documents suggested that Shell had considered the use of corrosion-resistant alloys for the line heaters and pipelines during the original design phase of the Carbondale system, but that the costs were found to be prohibitive.

Shell stated that it believed its engineering assessment approach was very conservative relative to usual industry practice. Combined with a conservative mitigation and surveillance program and the knowledge of the corrosion mechanism, Shell believed that the possibility of any further failure was extremely remote and that the integrity of the Carbondale system could be preserved into the future.

2.2.2 Views of the Interveners

In their submissions, the interveners disputed many of Shell’s views with regard to the preservation of the integrity of the Carbondale system into the future.

A key issue for the interveners was their view that the Carbondale system still contained both isolated and linked pitting and that Shell had not adequately addressed this issue in its stress analysis. The interveners stated that Shell’s calculations eliminated the 0.72 design factor commonly applied in ASME B31G and thus were not in strict accordance with that code.

The interveners stated that the B31G procedure contained a standard calculation that defined the maximum allowable pressure in a pipeline based on a number of factors, including length of clustered pitting, maximum depth of corrosion, nominal pipe wall thickness, pipe material strength, and pipe diameter. The procedure was developed by performing actual pressure tests on corroded sections of pipe and was used to determine what length of linked corrosion was deemed acceptable. The interveners stated that the CSA Standard only adopted a portion of the B31G calculation and that it was even more conservative because it did not take into consideration the system pressure and pipe material strength. The interveners believed that the IPCIT data that Shell had provided indicated that linked pitting still existed in the pipeline and that the longest incident was about 2.75 m, about ten times as long as what Shell had suggested. The interveners performed stress calculations on the 6-inch pipeline based on the above assumptions and concluded that many corroded pipe sections did not pass the calculations of either the basic CSA Standard or B31G methods.

In response to Shell's questions, the interveners stated that it was their opinion that Shell's engineering assessment approach was in violation of the CSA Standard. They stated that an engineering assessment should be based on sound principles, taking into account safety and the operating history of the pipeline. They did not believe that Shell had properly considered safety and suggested that based on the B31G graph using a safety factor of 1, the pipeline could fail catastrophically at pit depths above 47 per cent. They believed that Shell should have repaired or replaced the pipeline as opposed to continuing with an engineering assessment and that this would have been the proper, conservative approach.

The interveners also presented evidence showing results of some corroded pipe burst tests recently performed by BG Technology in England that indicated that pipelines operating near the maximum allowable operating pressures of the Carbondale system might fail slightly earlier than predicted by B31G. The interveners were concerned that Shell might currently be operating the Carbondale system within parameters that might result in failure.

In response to questioning, the interveners indicated that for the Carbondale system they believed it would be more appropriate to use the CSA Standard repair criteria rather than perform an engineering assessment using the methodology of either B31G or RSTRENG. Although they accepted that doing cutouts and repair would be in compliance with the CSA Standard, they indicated that they were still uncomfortable with that approach. The interveners argued that there was a risk that the numerous anticipated repairs that would be required may not be completed properly and that existing minor corrosion might also grow to the point where it would require repair. They also believed that the engineering assessment for this pipeline should incorporate either a 0.72 or 0.6 safety factor, and they stated that if they were performing failure predictions for this pipeline, they would tend to use a corrosion rate of about 1-2 mm per year. The interveners indicated that based on a 0.72 safety factor, a 20 per cent wall loss cutout criterion was appropriate, but only if a liner were installed to curtail further corrosion.

The interveners did not support the monitoring, maintenance, and cutout program put forward by Shell for the operation of the Carbondale system. They were concerned about the reliability of the IPCIT inspections, especially at pipe sections where the inspection tools ran either too slowly or too quickly. They felt that the IPCIT tool was not a precision device in the same sense that a corrosion coupon could be and was not capable of presenting the worst-case scenario, but would instead tend to show average values.

The interveners did not disagree with Shell's suggestion that the current higher gas volumes and velocities would help minimize corrosion problems caused by water or solids hold-up. However, they believed that an increase in flow rate would normally also require a higher operating pressure, which would in turn create additional stress on the pipe and reduce the margin of safety.

The interveners believed that the current corrosion program would not be effective in maintaining the damaged pipeline, as pigging and cleaning could not assure the removal of corrosion products and the resulting corrosive cells from already existing pits. For this reason, the interveners favoured the replacement of the corroded sections of pipeline. They believed that the existing corrosion control program would be successful on new pipe and that the existing level of mitigative activity could likely be reduced on new pipeline.

The interveners questioned the financial viability of the continued corrosion program at Carbondale and proposed that it could possibly be cost effective to either replace the pipeline or line it with a corrosion-resistant polymer liner. They recognized that these options represented significant capital cost, but felt that this could be justified based on the reduction of other inspection and mitigation costs. They also questioned whether it would be reasonable to consider replacing the pipelines with corrosion-resistant alloys rather than carbon steel.

The interveners were also concerned that Shell considered the Carbondale system operating costs to be high, and they provided detailed evidence suggesting that Shell was already planning to further scale back the costs of the corrosion mitigation program significantly. The interveners believed that Shell had barely gained control of this system and that to immediately start reducing the level of corrosion control activity based on the results received to date was irresponsible and carried a high risk of further failure. They argued that as the pipeline was already significantly damaged, an aggressive corrosion control program must be maintained.

The interveners expressed concern that Shell’s addition of sulphur solvent chemicals such as DMDS might compromise the effectiveness of the corrosion inhibitors Shell was using. They stated that Shell should continue to perform batch inhibition treatments after downhole DMDS treatments.

The interveners contended that Shell’s decision to change the corrosion inhibitor in the Carbondale system was made primarily in order to reduce problems at the Waterton gas plant and might not sufficiently protect the pipeline. They noted that the newly selected inhibitor did not appear to have an established track record for use in sour gas pipelines. Additionally, they were concerned that such changes to reduce operating costs could be or were being made without adequate testing and verification, as well as that such changes could occur inadvertently.

The interveners also expressed concern over the condition of the line heaters on the Carbondale system, as the heater coils were exposed to the same corrosive fluids. They suggested that the heater coils may be corroded as well and that further investigation should be performed.

The interveners also noted that there was some possibility of further sour gas development in the Castle River area. They believed that the Carbondale system should first be restored to a satisfactory level of safe operation before any new gas sources be allowed to use the pipeline. Any further development should also be carefully reviewed to ensure that no additional corrosion or operational problems were introduced into the system.

When considering the corrosion rate, the thin-wall design, and the damage that had occurred during the initial start-up of the Carbondale system, the interveners stated that they did not believe the operating life of this pipeline would be close to the design life of 15-25 years. They believed that allowing the system to operate as it was would represent an unacceptable risk to local residents and other users of the area. They noted that under current conditions, for the remaining life of the pipeline inspection and cutouts would be commonplace and any error in the operations management of this pipeline could be catastrophic.

2.2.3 Views of the Board

The Board must address the issue of whether the integrity of the Carbondale pipeline system can be preserved into the future and what, if any, changes need to be made to the system and its operational procedures to ensure its future safe and reliable operation.

The Board heard a considerable amount of testimony regarding the proper approach for the engineering assessment of corroded pipelines. The Board is of the view that the procedures followed by Shell do meet the general intent and requirements of the CSA Standard. The Board believes that the CSA Standard, the B31G method, the RSTRENG method, and the BG Technology method could all provide a valid approach in developing the basic requirements of an engineering assessment. However, the assumptions and criteria set by the user also influence the validity and interpretation of the final evaluation.

The process of conducting an engineering assessment in order to determine the suitability of a pipeline for service when in a compromised condition is an allowable practice within the context of the CSA Standard but requires consideration of a number of factors. A complete assessment requires the consideration of both the past operating history and the likely future operating conditions of the pipeline. For this reason, the Board believes that, due to the severity of past events, the application of a strength engineering assessment alone does not provide an adequate margin of safety for the purposes of assuring future integrity.

The Board also heard evidence on the reliability of IPCIT data. The Board notes that tool upgrades and operational optimization have managed to eliminate some uncertainty in the inspection data. However, the Board has reservations about relying on the accuracy of the data as representing absolute values and cannot rule out the possibility that some significant pits (30-35 per cent depth) may still exist in the pipeline. Furthermore, the Board notes that the engineering assessment uses average corrosion rates developed from the IPCIT data, and the Board is not comfortable with the possibility that isolated pits may be growing at faster rates than the average when considering the history of this system. As mentioned in the previous section, the Board also has concerns with the statistical approach used by Shell to calculate its average pit depths.

The Board is not persuaded that Shell’s recent optimization of its corrosion mitigation program is appropriate for the management of pipeline integrity on the Carbondale system. The Board believes that if a significantly corroded pipeline is to continue operating, then as a minimum requirement it must be accompanied by a very effective inspection, monitoring, and mitigation program. The Board does not accept that sufficient operating history had been obtained to justify any reductions in corrosion mitigation.

With respect to the suitability of installing corrosion-resistant liners, the Board acknowledges that liners can in some instances provide acceptable corrosion-resistant service but that they may not be suitable or practical solutions for all situations. Therefore, the Board accepts that this may be an option for Shell to evaluate and pursue if it feels it appropriate, but the Board does not require it. The Board further accepts that the installation of corrosion-resistant alloy pipeline materials would be a cost-prohibitive and unusual practice and should be unnecessary in a properly operated and maintained system.

The Board has considered the various proposals regarding cutout criteria as detailed by Shell and the interveners. The Board notes that both the CSA Standard and the B31G standard normally include a 0.72 factor for sour gas pipeline design and that the Alberta Pipeline Regulation requires a 0.6 factor. The Board agrees with the calculations that indicated that the 0.72 and 0.6 safety factors would result in approximately 35 and 25 per cent wall loss cutout criteria respectively. The Board considers these safety factors to be minimum design requirements for pipelines, and furthermore that these minimum requirements may not necessarily meet the requirements of every particular situation. When considering the nature of the product in the pipeline and the potential risk to the public, the Board is of the view that the application of a 0.6 factor would be appropriate in this assessment. The Board does not consider the RSTRENG technique to be conservative enough in this case, as it does not apply any safety factor. The Board also does not subscribe to Shell's belief concerning the separation of design and operating safety factors.

The Board is particularly concerned about the integrity of the portion of the 6-inch pipeline that is in proximity to the residents and the bottom of the creek valley. The Board heard evidence regarding the operating history of that pipeline that confirms that considerable damage to the pipeline has already occurred. As a result, the Board believes that even with a rigorous inspection and monitoring program, there remains a significant risk of future failure. The Board also believes that there is a reasonable chance that the flow rate in the pipeline may decline again to a level that could have a negative effect on the corrosion control program, further increasing the risk of failure.

The Board is not convinced that the 6-inch pipeline can be operated reliably and without further incident into the future without significant change. The Board notes that Shell's current mode of operation accepts that corrosion will be ongoing and then relies on the accurate prediction of corrosion rates, diligent and frequent inspections, and the cutout and replacement of damaged sections before they can leak. The Board believes that this is an irregular and unsuitable manner of operation that should not be viewed as sustainable for a sour gas pipeline and that may result in unacceptable impacts on the public. Therefore, the Board directs that Shell decommission lines 46 and 53 within two years of the issuance of this report and either replace the 6-inch pipeline within the existing right-of-way or find some other acceptable alternative means of transporting that gas to processing.

The Board does accept that currently neither the 6-inch nor the 8-inch pipeline is in imminent danger of failure. Therefore, in the short term the Board will allow the continued operation of these pipelines. However, the Board requires that Shell continue over the next two years to use the same level of corrosion control program that it had used during the first part of 1998. This includes a planning corrosion rate of 6 mm per year and 3 mm per year for the 6- and 8-inch pipelines respectively, with the concurrent inspection, inhibition, and pigging frequency made necessary as part of that program. The Board acknowledges that this may result in the ongoing need for relatively frequent flaring events, but in the short term considers this to be an acceptable condition while other longer-term options are being considered.

The Board also requires that during this short-term operating period, Shell continue to replace any and all joints of the 6-inch pipeline that demonstrate any pitting measured at 25 per cent wall loss or greater or that should develop to 25 per cent wall loss or greater. The 25 per cent cutout criterion shall be subject to the specified CSA Standard restrictions on pit length, as described in Section 10.8.2.2.4. Additionally, the Board expects Shell to apply this same 25 per cent cutout criterion to the operation of the 8-inch pipeline for the section running between Junction J and Junction K for the duration of its operational life.

Although no evidence was presented concerning the extent of corrosion of the heater coils, Shell must satisfy the Board that there is not an ongoing problem with corrosion at the line heater.

At the inquiry, there was some general discussion of the potential for future new sour gas production into the Carbondale system. Although this issue will be considered in future applications, the Board is concerned about the impact of the proposed additional sour gas production from the area on the long-term integrity of the Carbondale system. The Board accepts that producing more gas into the pipeline should increase the flow velocity and possibly help reduce the corrosion rate. However, the Board also recognizes that any flow increase would normally be accompanied by an increase in the operating pressure. While the pressure would be below the current maximum allowable operating pressure, this would in turn result in higher internal pipeline stresses and possibly increase the risk of failure of the corroded portion of the pipelines. As part of Shell's evaluation and planning for long-term development of the Castle River area, the Board expects Shell to conduct a diligent review of its entire Carbondale system, its suitability for further expansion, and the viability of alternative solutions.

2.3 Impact – What are the effects of the Carbondale system's operations on the health and well-being of local residents?

2.3.1 Views of Shell

Shell explained that a substantial amount of the previous activity at Junction J was in fact the result of its ongoing corrosion control program. Shell expressed its view that the sour gas flaring at Junction J has now evolved into a short-duration, intermittent activity, limited to depressurizing the pig barrels upon launching or receiving a pig. Shell stated that it had reduced flaring duration to the minimum time required to conduct the work safely. Shell noted that under its current program, the sweet gas pilot is lit just prior to the depressurizing activities and remains lit until the operation is complete. The sour gas flaring resulting from depressurizing of one or both pig barrels normally lasts from one to three minutes, for a total of only five to eight hours of sour gas flaring per year.

With regard to the frequency of flaring events at Junction J, Shell noted that at the outset of its enhanced monitoring program flaring frequency had been potentially as high as 160 events per year. Shell stated that as its pipeline inspection and mitigation programs became more routine, it had generally been able to limit sour gas flaring events to one day per week. As a result, Shell believed that through constant procedural modification it may have actually reduced the total amount of gas flared as compared to its earlier operations prior to the leak in the Carbondale system.

Shell stated that it had also attempted to minimize flaring at Junction J by flaring whenever possible at an alternate location, such as the 6-12 well site, the 12-9 well site, or Junction K. Shell noted that it had further reduced the volume of flared sour gas by depressurizing the pipelines to the suction of the compressor at Junction P whenever possible. Shell stated that it had also reduced the volume of flared sour gas and the potential for liquids reaching the Junction J flare by purging the piping with sweet gas prior to flaring. Sweet dilution gas is also added when flaring even small amounts of sour gas at Junction J. Shell observed that it had also eliminated one flaring event per pigging operation by coordinating pigging of the 6-inch and 8-inch pipelines at the same time. Shell indicated that increasing the rate of flow to the flare could further shorten the duration of flaring, but any increase in flow rate would also be accompanied by an increase in noise. Shell stated that it had made arrangements to contact the Sheppards and Mr. Judd prior to any flaring event and to inform them of the purpose of flaring and its expected duration.

With regard to alternatives to flaring at Junction J, Shell stated that it did not believe an incinerator was warranted or practical, given the extremely short duration of flaring and the small volumes of sour gas being flared. Shell felt that the operation of the incinerator, considering the fuel gas required, could result in more emissions than occur under the current operating protocol.

When questioned as to whether replacement of the existing Carbondale system with a new carbon steel pipeline would reduce the level of activity at Junction J, Shell noted that since much of the flaring at Junction J was the product of its corrosion control program, replacing the existing pipeline would still require virtually the same level of activity. However, Shell also noted that since it had now demonstrated the success of its corrosion program, it anticipated further reducing activity levels and flaring at Junction J. Shell indicated that it was also attempting to reduce the impact of activity around Junction J by instructing field operations staff to reduce speed while driving near Junction J and by controlling the noise produced by various contractors working for Shell.

Shell acknowledged the complaints of the Sheppards with regard to noise from the line heater at Junction J. Shell noted that a noise survey conducted in 1991 had indicated some situations where it may possibly exceed the EUB’s nighttime noise guidelines. Shell committed to perform another noise survey and to address the concerns of the Sheppards with regard to the noise problem. Shell confirmed that, at a minimum, a currently noisy check valve at the Junction J site would be fixed.

With regard to emissions from operations at Junction J, Shell submitted that under certain atmospheric conditions the operation of the flare could result in ground-level SO_2 levels that exceed the Alberta recommended levels in proximity to the flare. It predicted, however, that the highest concentration would occur directly east of Junction J, and that the Alberta recommended levels would not be exceeded at any of the local residences. This estimate was based on what Shell believed were well-established modelling procedures considered to routinely overestimate the true condition. Shell also indicated that while the prevailing winds would be expected to carry the flare plume in the direction of the Sheppards' residence, the rugged nature of the local topography was expected to generally increase turbulence and therefore dispersion. Shell stated that it believed the likelihood of flaring occurring simultaneously with the exact atmospheric conditions necessary to result in high ground-level SO_2 concentrations was extremely small. Shell noted that this belief was supported by the results of its air-monitoring program (see below). Shell also stated that even if this unlikely overlap of events did occur, the short duration of flaring events meant that any persons in the vicinity would receive only a short exposure. Shell submitted that toxicology studies of the chemical compounds that could be expected from the flare gases indicated that adverse effects would occur only from concentrations administered in large excess either of concentration or of duration. Shell believed that there would be no adverse effect resulting from the infrequent, short-duration exposures that might be expected from the flaring events at Junction J.

Shell stated that it had conducted air quality monitoring for both SO_2 and H_2S in the area of Junction J. Shell stated that the results of 45 days of monitoring at the Sheppards' residence and four mobile monitoring events conducted by the EUB indicated a maximum level of SO_2 of 0.02 ppm during any of the flaring events conducted during these monitoring activities. Shell observed that this recorded level of SO_2 falls well below the Alberta Environment guideline maximum value of 0.17 ppm for a one-hour average. Shell also stated that on only one occasion during the monitoring was the odour of H_2S detected.

2.3.2 Views of the Interveners

The Sheppards expressed the view that Shell's operations have had an intrusive and deleterious effect on their lives. They noted that when they built their home in 1977, the pipelines, wells, and Junction J were inactive. The Sheppards stated that around 1984 Shell approached them about constructing a new set of facilities at Junction J and a pipeline from the 5-20 and 6-17 wells. The Sheppards contended that Shell's personnel assured them then that noise would not be a problem. However, the Sheppards maintained that the line heater located at Junction J did result in an intrusive level of background industrial noise.

After advising Shell of their concerns, the Sheppards stated that they believed Shell attempted to minimize the noise problem by changing patterns of heating at Junction J and other well sites, but that overall the result was still unsatisfactory. The Sheppards noted that Shell arranged for noise testing in 1991. However, they felt that the test unit was not placed in a location that would obtain meaningful results relevant to their home. The Sheppards also noted that although the testing indicated that the noise levels might be exceeding recommended nighttime standards, to their knowledge no corrective measures were taken by Shell.

The Sheppards stated that in 1994 Shell approached them about building a pipeline from the suspended Carbondale wells 7-20, 12-9, and 6-12, located to their west. This production would be brought into Junction J via a new 6-inch pipeline and then be carried in a new 8-inch pipeline towards Junction K via the southwest corner of the Sheppards' property. This was to be accommodated on the west side of the existing easement, as per the Sheppards' preference. The Sheppards believed that at that time they had expressed their concerns about flaring at Junction J to Shell and had been assured that flaring would be infrequent.

The Sheppards stated that when they agreed to the new pipeline, they were unaware of the eventual implications. They stated that they did not understand that bringing a 6-inch pipeline into Junction J and leaving with an 8-inch pipeline would require flaring every time pigging was conducted. Up until this point, flaring operations at Junction J had been very infrequent and not of concern to the Sheppards. In fact, they felt there was no problem with flaring at Junction J until after the first pipeline failure.

The Sheppards observed that since the failure, the frequency of flaring incidents had increased significantly. At the inquiry, the Sheppards produced photographs showing occurrences of large flares from nearby Shell facilities. The Sheppards stated that they have also grown increasingly concerned over the possible longer-term toxic effects of flaring. They objected to the unwanted exposure to the various and possibly carcinogenic combustion by-products of the flares, whether they were from sweet or sour gas combustion. They felt that the effects of chronic exposure, even at low concentrations, may be cumulative and that there was growing scientific evidence supporting this belief. They believed the lower threshold levels required to produce adverse effects are unknown, especially in the long term, and that Shell should not have the right to spread such pollution onto their property or themselves. Regardless of estimated concentrations, they regarded any exposure as an unwanted and unacceptable threat to their health.

The Sheppards believed that the monitoring carried out to date did not suitably evaluate the exposure they may actually be experiencing, particularly as their exposure is significantly influenced by topography and variable atmospheric conditions. They stated that they have repeatedly recorded odours at their residence. The Sheppards described one incident where, although they detected a fairly strong H_2S odour at their porch, the monitoring equipment in place at the time failed to detect the presence of H_2S. They believed that continuous monitoring was necessary to adequately monitor the flare stack emissions and that the monitors must be located in locations that would be more likely to reflect the conditions at their residence.

The Sheppards stated that the noise generated by the line heater at Junction J had also continued to be a source of irritation and that they had continued to make their dissatisfaction known to Shell.

The Sheppards presented evidence, in the form of an activity log, showing that there had been a significant increase in the level of activities relating to the operation and remediation of the Carbondale system, resulting in a significant intrusion into the peace of their area. Activities such as well servicing, chemical treatment, pigging, flaring, excavating, and pipeline right-of-way inspection had resulted in increased light vehicular and heavy truck traffic, all of which travelled on roads passing within about 200 m of their residence. The traffic produced additional noise and

dust, and certain types of work created heavy machinery and radio communication noise. The Sheppards indicated that they believed Shell personnel were attempting to control noise, but that often their contractors were not sensitive to this goal.

The records presented by the Sheppards indicated the presence of some sort of industry activity in their area on at least 148 days of 1998, and Mrs. Sheppard described the level of activity as being "relentless." The Sheppards stated that they also resented having to spend such a significant amount of their own time over the last three years dealing with the oil and gas industry, including monitoring activities, phone calls, meeting company representatives, preparing for and attending hearings, and all the associated stress from this involvement. The Sheppards felt this was a substantial infringement on their lives.

The Sheppards stated that the development of two leaks, resulting from different causes and occurring on a new pipeline within a short time, did not give them much confidence in the integrity of that pipeline. As a result, living near the pipeline caused them a great deal of concern for their family's safety and health. They considered it only a matter of luck that the leaks had not occurred nearer to their home and that no persons had been in the vicinity of the leak when it occurred.

The Sheppards believed that if Shell were allowed to continue to operate the existing Carbondale system, they would still have to endure a flaring schedule that would not change significantly from that used over the last year and that the heavy traffic and noise levels would continue. They stated that this was not acceptable.

The Sheppards also expressed their opposition to several new wells that they believed were being planned for the area. They were concerned that these wells might be tied into the Carbondale system, leading to increased risks to the corrosion control program and associated risks of pipeline failure. They were also concerned that this would result in even higher activity levels at Junction J and elsewhere around their property, including the possibility of more flaring both during drilling as well as subsequent operations.

Assuming that only the current wells were producing, the Sheppards believed the best solution to the problems caused by the Shell Carbondale system would be to move Junction J farther downstream and out of the Screwdriver Creek valley and build a new pipeline to replace the 6-inch pipeline from the three existing wells to the new Junction J location. They did not support the building of a new pipeline to connect with the Canadian 88 pipeline to the north. The Sheppards did not see an obvious solution for handling the production of any new wells proposed for their area.

The Sheppards questioned the safety of the crossover from the 4-inch North End system to the Carbondale system. They referred to Shell documents that they believed suggested that in the event of a leak on the 8-inch pipeline, the automatic pipeline block valve upstream of Junction J on the North End system might not close, and thus the North End system might feed a leak in the Carbondale system. They agreed that there is another pipeline block valve on the North End system located at Junction J, but noted that its operation is controlled only by operator intervention from the Waterton Control centre. The Sheppards stated that they resented the fact that Shell was reluctant to install an automatic valve operator on this valve, but instead was willing to impose a higher level of risk on the residents living near Junction J.

2.3.3 Views of the Board

The Board must consider whether the Carbondale system can be operated into the future in a manner that does not result in unacceptable impacts on area residents.

The Board notes that the ongoing construction and pipeline maintenance operations of the Carbondale system since 1995 have resulted in a high level of activity in the Screwdriver Creek valley, particularly around Junction J. The Board further accepts that much of this activity, including current flaring levels, has occurred as a result of Shell's efforts to address the root causes of the failures. As a result, this level of activity was clearly not anticipated either when Shell applied for the current facilities or when the EUB gave its approval. The Board recognizes that Shell has expended considerable effort to streamline its procedures in order to minimize the impacts of its operations on the Sheppards and other residents. However, it is apparent that the corrosion mitigation program has resulted in a considerable disruption to the residents in the area near Junction J and that some residents do not view Shell's efforts as either sufficient or successful.

The Board is prepared to accept that flaring events are generally of short duration and that air monitoring and testing have confirmed that the level of emissions very likely does not exceed acceptable standards. At the same time, it is evident that the prevailing winds would often be expected to carry flare stack effluent past the Sheppards' residence. If nothing else, this may create considerable nuisance for the Sheppards and certainly adds to their general concerns regarding Shell's operations. The Board agrees with Shell, however, that an incinerator would not provide an adequate solution to this situation, given the short duration of the flaring events and the fact that incineration is more suitable for a sustained operation.

The Board notes that the 1991 noise data for the Junction J site indicated that unacceptable nighttime noise levels may have been occurring. The Board also notes that no additional information was presented by Shell at the inquiry that would indicate that those earlier conditions had substantially changed or what efforts Shell had made to address area noise concerns. Therefore the Board believes that the sound levels from Junction J may on occasion continue to exceed EUB requirements.

The Board believes that, having regard for the operations that have evolved from the corrosion problems, the location of Junction J relative to the Sheppards' residence is much less than optimal. Furthermore, the type of work being conducted there is markedly different from and more frequent than that which would have been originally communicated to both the residents and the Board when the application for the facilities was made. As a result, the Board finds that Junction J, at least in its current configuration, has become unsuitable for long-term operation.

Therefore, Shell is required to re-examine Junction J, determine how it can best redesign this facility in order to ensure that impacts on area residents are further reduced, and submit this plan to the Board for its approval within three months of the issuance of this decision report.

Shell is also required to immediately confirm existing noise levels from Junction J and to make reasonable efforts to mitigate the noise levels from the line heater and other facilities at Junction J so that the levels meet the requirements of the Board's noise directive. Furthermore, a fully automated valve operator must be installed in the 4-inch crossover at Junction J, as the existing method of manual intervention in the operation of the pipeline block valve is not considered to be adequate. The automatic valve must be coupled so as to close concurrently with the closing of the other pipeline block valves. The valve modification and noise control remediation efforts are to be completed within three months of the issuance of this decision report.

2.4 Communication and Community Relations — What has been the relationship between the company and the community?

2.4.1 Views of Shell

At the inquiry Shell stated that it values its relationship with community members and neighbours and that it works hard to minimize the impacts of its operations. Shell felt that it had made significant efforts to address odours, noise, and flaring issues at Junction J.

Shell stated that it has a comprehensive emergency response plan (ERP) in place and an effective process of communicating that plan to the public. Shell noted that specific plans are prepared for each potential hazard and trained personnel are identified to carry out the plan. Shell pointed out that the plan includes a 24-hour phone line, a structured command and communication system, practice and drills, and liaison with the appropriate government authorities.

Shell noted that it contacts all residents annually to update the information in the ERP. Shell stated that it visits all residents personally every second year to review and explain the plan and any changes to it. Information packages are distributed outlining the plan and the appropriate response to an emergency.

Shell stated that it also notifies residents when any significant activity is planned for their area. The recommissioning of the repaired Carbondale system in spring 1998, well test flaring in 1997 and 1998, and pipeline excavations in 1997 and 1998 were, in Shell's view, some examples where such notification was provided. Shell stated that it intended to continue to consult with its neighbours and keep them informed of its activities.

Shell acknowledged at the inquiry that its relationship with the Sheppards was strained and that despite long-term complaints from the Sheppards, none of its senior management staff had taken the opportunity to meet with them to discuss their concerns.

2.4.2 Views of the Interveners

The Sheppards indicated at the inquiry that in their view there was very little effective communication with Shell. For example, they noted that following the Burmis pipeline hearing in 1997, and at the urging of the Board, they and Shell met in January 1998 to discuss air quality and flaring. The Sheppards stated that they had asked Shell to provide continuous air monitoring but that Shell would not agree. In the Sheppards' view, this was because the company felt such monitoring was both inaccurate and unduly expensive. Eventually, a mobile monitoring unit was provided by Shell, after a series of negotiations that the Sheppards described as being very frustrating.

The location of the unit was also problematic. The Sheppards stated that they had wanted the monitoring trailer located to the south of their house because the plume travelled in that direction. This location was also important since the field located south of the house was their only feasible future building site. At the inquiry, the Sheppards noted that only after numerous telephone calls and meetings was it agreed that mobile monitoring would be conducted on three occasions in the south field during flaring events. The Sheppards regarded this as confirmation that their concerns were not genuinely addressed by Shell.

The Sheppards stated that they had also believed that air quality monitoring would be completed by fall 1998. However, it was not completed until March 1999. Dr. Sheppard testified that he had to call Shell at least twice to remind them of their commitment to arrange for the monitoring.

The Sheppards testified that prior to the Burmis pipeline hearing they were unaware that an ERP was required for the Carbondale system. They stated that they had Shell's emergency telephone number and knew to report odours, but that no one from Shell had ever met with them to review the plan and explain details until they requested this from Shell in early 1998.

The Sheppards stated that they also did not have much confidence in the plan. They noted that they live on a dead-end road, which could prevent evacuation, depending on the location of a leak. They also believed that they were also not always notified of relevant events. For example, they stated that no one from Shell informed them of the 1997 weld failure until three days after it was detected, despite their being the closest residents to the leak. They testified that in 1996, after smelling sour gas near Junction J, they called Shell's emergency number but found it to be discontinued. A recording gave another number, but no one answered that phone. After telephoning the Shell field office, someone finally did respond, and the apparent cause was found to be a valve leak at Junction J. The Sheppards stated that given their experience with these incidents, they are concerned that any notification of major leaks to residents will not be timely. They also cited several other examples where they felt that public notification had not been performed adequately and stated that they wanted the ERP to be revised and examined more regularly.

In general, the Sheppards stated that they believed that Shell's performance in meeting their concerns was poor and had deteriorated over the past two or three years. The Sheppards noted that in spring 1998 Shell had offered to repeat the noise monitoring program, but subsequently withdrew its offer for reasons unknown by the Sheppards.

The Sheppards stated that they had found that Shell answered questions promptly but remediation actions required repeated reminders and dragged on over long periods. For example, the Sheppards stated that during the meeting in January 1998, they had raised concern over long-standing water damage on the 1986 right-of-way and 1995 right-of-way damage due to pipe replacement. Although Shell agreed to fix it, Dr. Sheppard stated that he had to phone in August 1998 to remind Shell again. In September a contractor fixed the problems on the 1995 right-of-way, but seemed unable to provide a solution for the water damage on the 1986 right-of-way. In February 1999, the Sheppards called Shell about the problem again. That month a consultant inspected the right-of-way and suggested a remedy that was to be implemented in May 1999.

2.4.3 Views of the Board

The Board concludes that Shell has failed to meet the expectations of the public and of the Board in dealing with the local residents in the vicinity of the Carbondale system. Open and meaningful communication between industry and affected persons is one of the principles most strongly encouraged by the Board. The Board feels that most disputes can be mutually resolved if parties discuss issues in good faith. In this case, although Shell may have believed that it was doing everything reasonable to alleviate the concerns of the Sheppards, its actions did not foster any confidence that Shell truly understood the Sheppards' concerns or was willing to try to protect their interests.

The Board believes that it is incumbent on operators to be responsive to public concerns and provide proper follow-up on its commitments in an effective and timely manner. Members of the public should have a reasonable expectation when dealing with a company that the company will take responsibility for its operations and act in a timely fashion. The public should not be required to take the lead in ensuring that agreements are met or be forced to expend inordinate amounts of time and energy in order to understand existing and planned developments. In this case, the Board does not believe that Shell has adequately met those responsibilities.

The Board is particularly concerned about the contradiction in evidence presented by Shell and the Sheppards concerning the ERP and the contacts and communication around it. The evidence did not give the Board confidence that should a need to implement the plan arise, the plan would be current and the residents would know what to expect or whom to contact. The Board therefore requires that Shell review its emergency response planning and communication in light of the Sheppards' comments and take appropriate action to ensure the plan is current and can be performed in the event of an emergency.

The Board is also disappointed that Shell initially resisted participating in this public inquiry, resisted providing information until directed to do so, and has throughout the course of this proceeding taken the position that the interveners were not entitled to contest Shell's operations, did not have meaningful grounds for the request of an inquiry, and as such should not be eligible to recover costs. The Board believes that operators must take responsibility for their operations seriously and be prepared to openly discuss their actions with the public and their regulatory agency when faced with the kinds of operational difficulties that have occurred at Carbondale.

Companies must gain, hold, and if necessary regain the confidence of the public and community in which they operate by full and open disclosure of their actions and their reactions to operational incidents and complaints.

Shell's failure to meet even minimum communication expectations, coupled with concerns regarding future sour gas leaks, has caused the residents to lose confidence in Shell's ability to operate its system in the interests of the public. The Board does not believe that this confidence can be re-established sufficiently to allow the operations as they are currently conducted within the Screwdriver Creek valley to continue. Therefore, Shell, when preparing its development plan for the area as required in Section 2.3.3, is required to include the relocation of Junction J from the Screwdriver Creek valley.

3 CONCLUSIONS OF THE INQUIRY

The Board is satisfied that this inquiry has allowed for open communication of the various parties' views and positions. In addition to the conclusions contained in the preceding sections, the Board further makes the following general conclusions:

- The causes of both of the pipeline failures have been determined and the mechanisms that contributed to the failures are understood. Appropriate communication has been made to industry so that they can consider this information relative to their operations.

- Shell has identified appropriate practices that, if followed, are sufficient to ensure that future failures of this nature can be prevented.

- Although corrosion rates in the Carbondale system appear to have been significantly reduced, the extensive nature of the initial damage plus the inherent uncertainty around the corrosion measurement tools have resulted in an unacceptable longer-term risk of failure in the Carbondale system.

- Therefore, an immediate reduction in the amount of allowable remaining corrosion from 35 to 25 per cent (of total wall thickness) for both the 6-inch and 8-inch lines, plus the near-term decommissioning of the 6-inch lines are considered to be in the public interest.

- The inquiry found that there has been a significant increase in activity and need for operational intervention in order to ensure system integrity, coupled with a serious failure by Shell to meet the Board's expectations with regard to landowner relations.

- As a result, further reductions in the impacts on the interveners resulting from the operation of Junction J are to be implemented immediately. In the long term, Shell must reconfigure the Carbondale system so that Junction J can be removed from the Screwdriver Creek valley.

DATED at Calgary, Alberta, on 12 October 1999.

ALBERTA ENERGY AND UTILITIES BOARD

[Original signed by]

B. F. Bietz, Ph.D., P.Biol.
Presiding Board Member

[Original signed by]

K. G. Sharp, P.Eng.
Acting Board Member

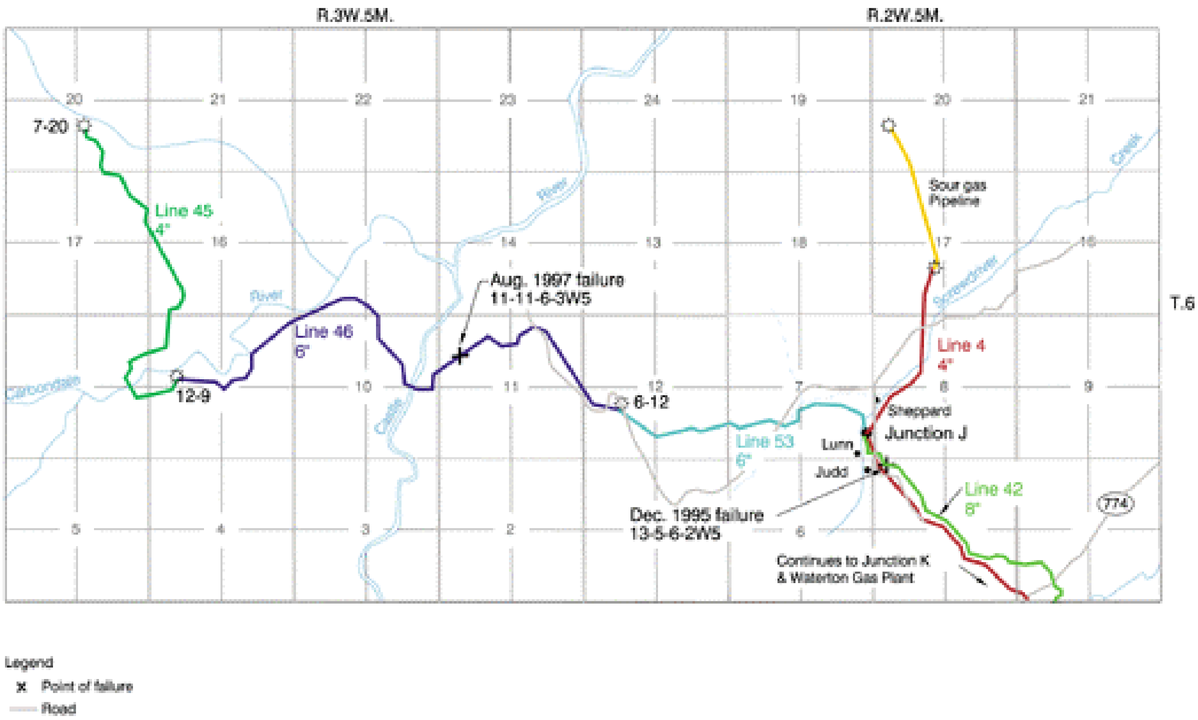

Figure 1. Shell Carbondale system, North End system, and Junction J
Shell Canada Limited
Proceeding 980058

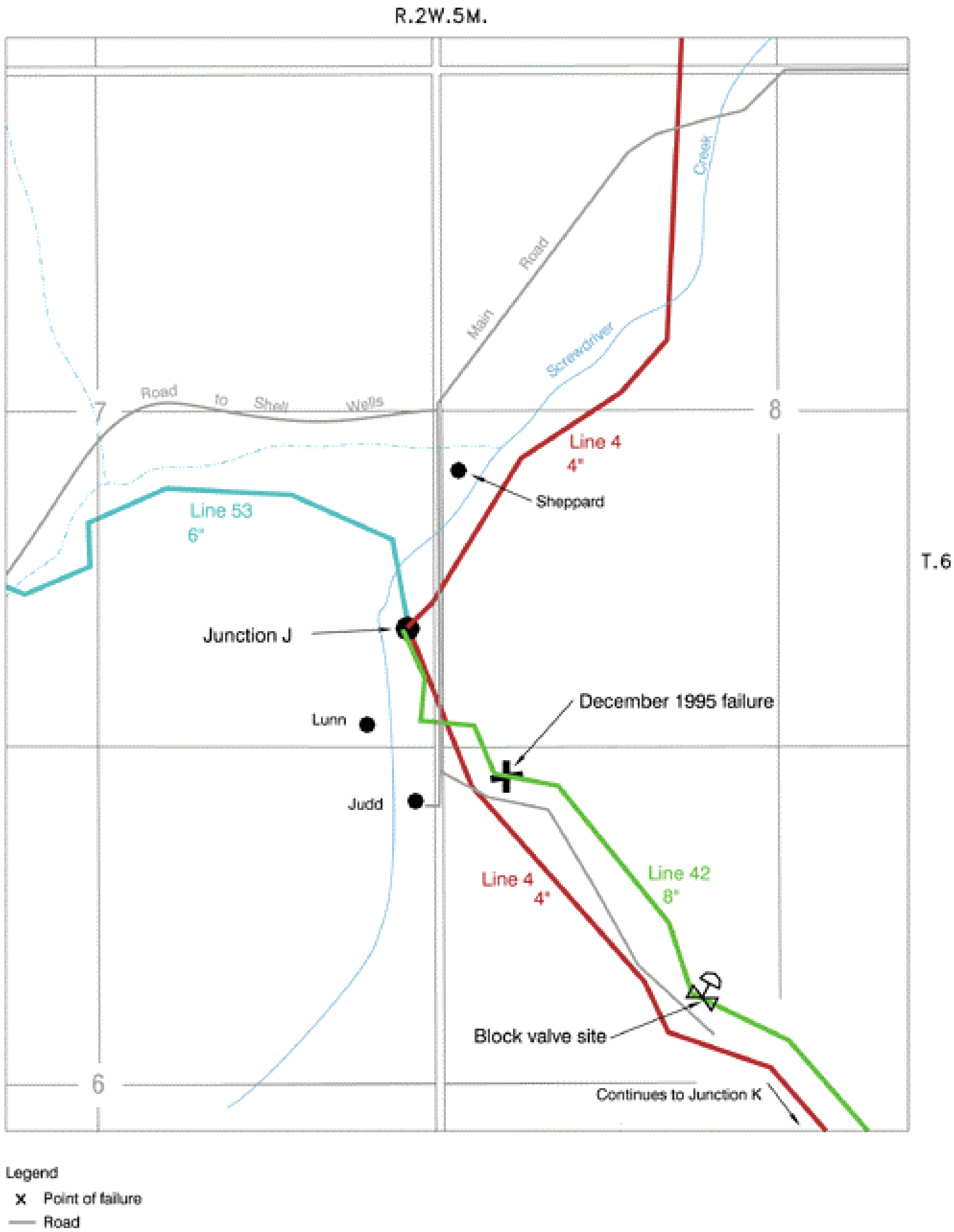

Figure 2 Shell Carbondale Junction J
Shell Canada Limited
Procedding 980058

Decision 99-24