Higher Design Factor Review and Considerations

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The operation of grandfathered pipelines in the U.S. coupled with research conducted on the operation of these pipelines indicates that pipelines can be safely operated with design factors above 0.72 up to 0.87. Operation of pipelines in Canada with design factors up to 0.80 has been implemented since 1973. In the England, pipelines are operating with design factors up to 0.78. Australia is currently proposing to adopt design factors up to 0.80.

This review will summarize the operation of grandfathered pipelines in the U.S. operated at design factors above 0.72. A brief review will be presented on the Canadian adoption of design factors up to 0.80. Finally, recent PRCI research on the assessments necessary for operation with design factors up to 0.80 will be presented.

Summary of Grandfathered Pipeline Operation in the U.S. With Design Factors Above 0.72

The American Society of Mechanical Engineers (ASME) summarized data on pipelines operating with design factors over 0.72 as a proposal to the B31.8 Standards Committee in 1980. The proposal summarized the prior operation of pipelines from 1953 to 1979 with design factors above 0.72 that had been tested to more than 90% SMYS with many of the pipelines operated at 80% of the test pressures, which were in excess of 100% SMYS. In the 1990's, the companies involved were questioned about the way in which they operated and maintained the pipelines with design factors over 0.72.

The data in Table 1 are from seven gas transmission companies that had tested pipelines over 90% SMYS and then operated them with design factors from 0.73 to 0.87. The total length of pipelines operated with design factors above 0.72 is 5563.2 miles for a total of 62,606.9 mile-years of operation as shown in Table 1 from 1953 to 1971. An additional 679.5 miles of pipeline continued to operate from 1971 to 1979 for an additional 5436 mile-years as shown in Table 2 for a total of 68,043 mile-years.

Figure 1 indicates that the high mile-years were for pipelines operated with design factors of 0.74, 0.77 and 0.85. These data for the 0.77 and 0.85 design factors represent about 45,000 mile-years of operation. Thus, as experimental pipelines, these 0.77 and 0.85 design factor pipelines represent approximately 13 years of pipeline operation with design factors above 0.72. This is a significant amount of data to demonstrate the usage of >0.72 design factors for pipelines.

Table 1. Summary of Pipelines Operated with Design Factors > 0.72 from 1953 to 1971 in the U.S.

Design Factor x 100	Miles	Mile-Years	Year Operation Started	Original line Defects		Damage after test	Time dependent	Other causes
				Leaks	Failures			
73	47.6	138.1	1968	1			1	
74	839.6	7240.1	1962	2				
75	740	5509.8	1964	2		1	1	
77	2486.3	32179.3	1958	5		3	2	1
78	235.6	4240.8	1953	1		1		
80	92.3	369.2	1967					
81	224.5	2100.6	1962	2		2		1
83	97.1	601.8	1965					
85	772.5	10144.1	1958	3			2	
86	15.8	47.4	1968					
87	11.9	35.7	1968					
Sub total >72	5563.2	62606.9	31	16	0	7	6	2
Subtotal <72	31583	153537.6	62	50	0	4	6	2
Totals	37146.2	216144.5		66	0	11	12	4

Table 2. Summary of Pipelines Operated with Design Factors from 1971to 1979 in the U.S.

Design Factor x 100	Miles	Mile-Years	Year	Original line Defects		Damage after test	Time dependent	Other causes
				Leaks	Failures			
74	582.1	4656.8	1971	1			1	
77	32.0	256	1971	2				
76	65.4	523.2	1971	2		1	1	
Totals	679.5	5436.0		5	0	1	2	0

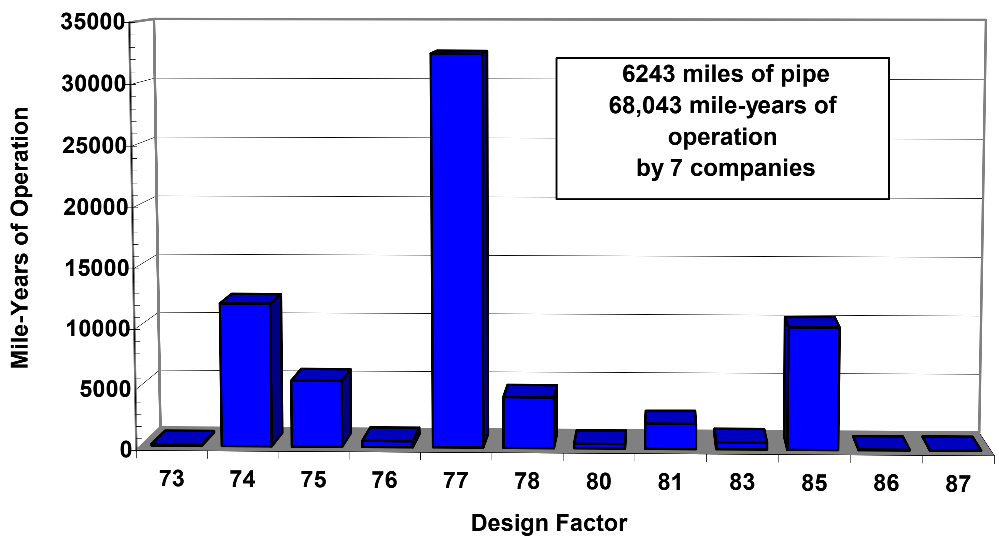

Figure 1. U.S. Operation of Pipelines with Design Factors > 0.72 From 1953 to 1979

The pipe grades involved for the 37,146.2 miles of pipe summarized in Table 1 are shown in Figure 2. These data represent pipe operated above and below a design factor of 0.72. Fifty eight percent of the pipe is X52 or less based on miles of pipe in service and 35 percent of the pipe is X60 with 5 percent X65.

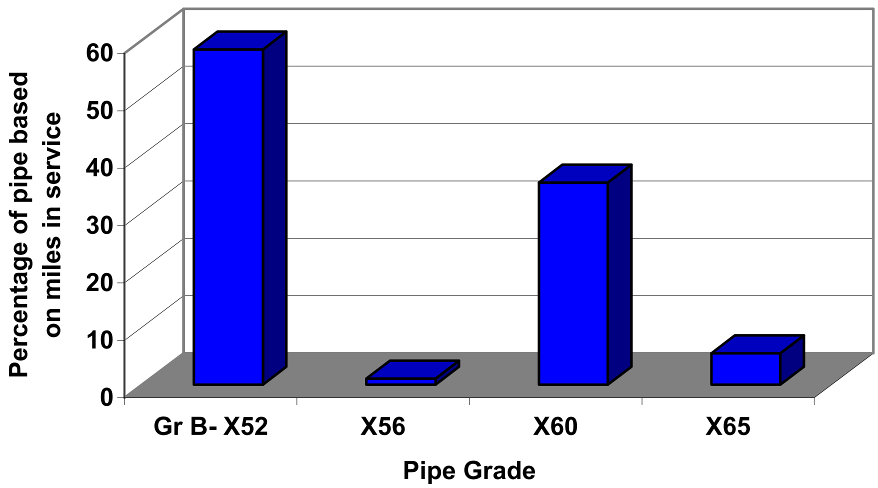

Figure 2. Pipe Grades Involved in All of the Pipelines Operated by the Seven Transmission Companies

Figure 3 presents the range of diameters for the pipelines in Tables 1 and 2 operated with design factors above and below 0.72. The diameters range from 4 to 46 inch with a high percentage of the pipe being 20 to 36 inch diameter.

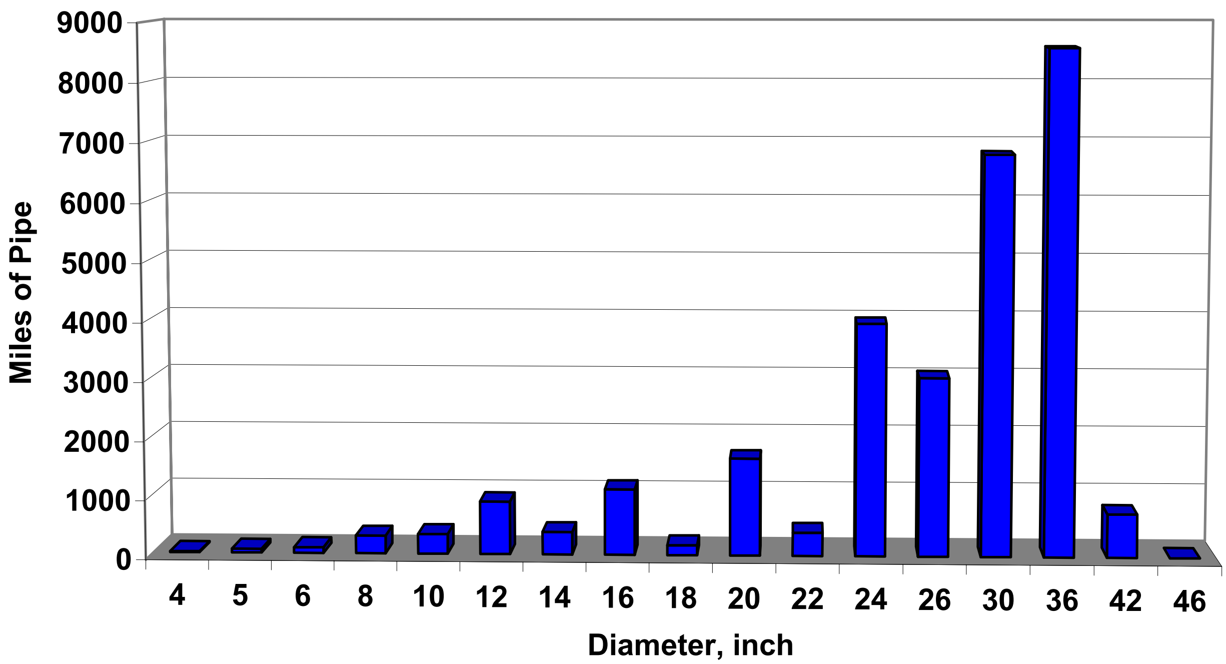

Figure 3. Miles of Pipe by Diameter for Tables 1 and 2

The pipelines represented in Figures 1-3 were produced between 1953 and 1968. Research was conducted in the 1960's on line pipe steels to improve their fracture properties but it was not until 1968 that API included a recommended practice (API 5L SR5 & 6) for specification of a transition temperature on the purchase order and thus, very little of the line pipe in these pipelines was representative of the types of pipe properties, manufacturing and NDT inspection capabilities that are available in current pipe production.

These data show that pipelines can be operated with design factors above 0.72 when tested to 90% SMYS or higher. However, the safety aspect or numbers of incidents resulting from the experimental operation is quite revealing. The incident history for the pipelines presented in Table 1 compared to pipelines operating with design factors less than 0.72 is shown in Figure 4. Shown are data for three groups of pipelines: 1) pipelines that were operated with design factors above 0.72 by seven companies, 2) similar data for the same companies operating pipelines with design factors of 0.72 and below, and 3) all of the U.S. pipelines operated with design factors of 0.72 and below during the time period from 1953 to 1971.

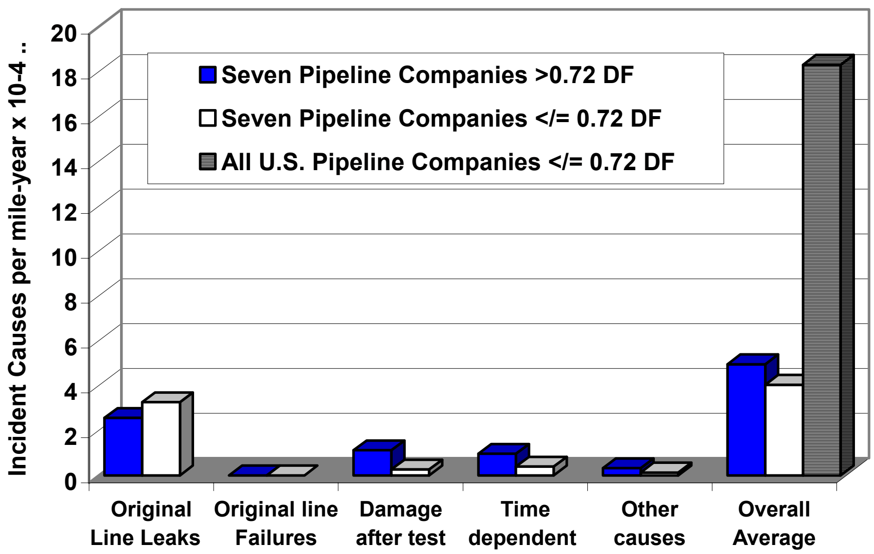

Figure 4. Incident History for Pipelines With Design Factors >0.72 and ≤0.72 Operated from 1953 to 1971

Figure 4 illustrates the safety (incidents) that was associated with the experimentally operated pipelines with design factors above 0.72 contrasted to pipelines operated with design factors of 0.72 and below. The three bars at the right represent the incident averages in mile-years x 10^{-4} for these pipelines with design factors above and below 0.72 for the seven participating companies. Also shown are the incident averages for all U.S. pipelines during this period based on data from the Federal Power Commission and OPS for pipelines operated with a design factor below 0.72. The figure indicates that the seven pipeline companies had incident levels of 5.0 x 10^{-4} incidents per mile-year for pipelines with design factors above 0.72 and 4.0 x 10^{-4} incidents per mile-year for pipelines with design factors of 0.72 and lower. These data indicate that the lower design factor pipelines had 20 percent fewer incidents. However, the revealing data was the comparison of the seven companies incident rates of 4.0 and 5.0 x 10^{-4} per mile-year with all of the pipelines, which had incident rates of 18.3 x 10^{-4} incidents per mile-year or over 300 percent higher than the seven companies pipelines with design factors above and below 0.72, which is a significant difference.

This significant difference in incident rates raised a question as to what the seven pipeline companies were doing that the others were not. A survey of these companies was conducted in the 1990's and revealed that these companies had been applying a risk management approach to the higher design factor pipelines that carried over to their 0.72 design factor pipelines resulting in the significantly reduced incident rates.

Another observation from Figure 4 is that the cause category with the highest incident rate was the original pipeline leak category, which represented mill defects and construction defects. This is further indication of the quality of the line pipe that was involved in the experimentally operated pipelines compared to currently produced line pipe, which rarely experiences an original pipeline leak due to improved material properties, mill NDE inspection, mill welding and field welding technique improvements along with improved construction techniques.

Figure 5 compares data from the OPS incident database from 1984 to 2001 in which the failure stresses were calculated based on the available data (note: 966 incidents out of 1199 were complete enough for the calculation of stress level). The percentage of gas pipeline incidents has been plotted versus the operating stress normalized by dividing by the specified minimum yield stress (SMYS) of the pipe creating a simulated "design factor".[1] The conclusion is that the highest percentage of incidents occurred on pipelines where the stress level at failure was less than 0.40 SMYS. The incident rate for the 0.60 to 0.72 SMYS stress level lines is about 60 percent of that for the 0.40 SMYS stress level pipelines. It is also significant that only 2 percent of the incidents occurred on gas pipelines with stress levels above than 0.72 SMYS. These data indicate that stress level and hence design factor does not control incidents or the safety of pipelines.

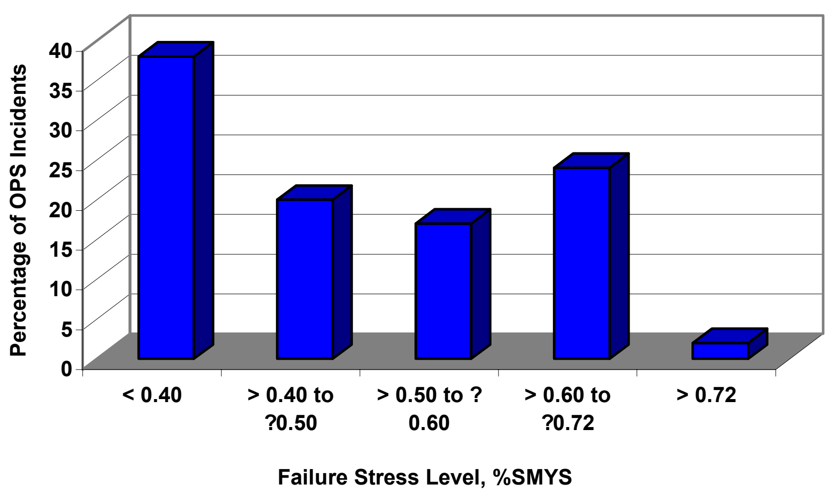

Figure 5. Percentage of OPS Incidents Versus Stress Level

[1] Eiber, R.J., McLamb, M., and McGehee, W. B., Quantifying Pipeline Design at 72% SMYS as a Precursor to Increasing the Design Stress Level, GRI-00/0233, Appendix C, December, 2000.

Canadian Application O.80 Design Factors

The CSA Committee on Oil Pipe Line Code started work in early 1962, followed by the Gas Pipe Line Code Committee about a year later to develop CSA Codes for pipelines. In June 1967, the first edition of CSA Standard Z183, *Oil Pipe Line Transportation Systems*, was published. In March of the following year, CSA Z184, *Gas Transmission and Distribution Piping Systems*[2] was published. Both standards were based extensively on the provisions of ASA B31.4 and B31.8, respectively.

CSA Z184-1968 Gas Transmission and Distribution Piping Systems

The Class Location concept that had been introduced in the 1955 edition of B31.8 for determining the design and testing requirements for pipelines was one of the requirements incorporated into CSA Z184-1968. The design factors for Class Locations 1, 2, 3 and 4 were 0.72, 0.60, 0.50 and 0.40, respectively.

For pipelines in Class Location 1 .e. cross country pipelines), the design factor of 0.72 was based on the application of a safety factor of 0.80 on the mill test pressure, typically 90% SMYS, and the maximum allowable operating pressure was limited to 80% of the test pressure. However, test pressures were limited to the first confirmed deviation in the pressure-volume curve. Although the MAOP was not limited to the design pressure, it would have been unlikely that MAOP's significantly above those corresponding to 72% SMYS could have been achieved.

In the second edition of the CSA Z184 standard, published in 1973, two key amendments effectively raised the threshold for operating stress levels.

The first amendment set the maximum test pressure at the pressure corresponding to the 0.2 percent offset on a pressure-volume curve. This effectively allowed test pressures to exceed a hoop stress equal to the SMYS. Secondly, the relationship between MAOP and test pressure was spelled out explicitly. For gas pipelines tested with an approved liquid, the MAOP was defined in Table 3 (Table 15 in CSA Z184-1973).

Table 3. CSA Z184-1973 Allowable Operating Pressures

Class Location	Maximum Allowable Operating Pressure (Lesser of)
1	t.p. /1.25 or 0.8 SMYS
2	t.p. /1.25 or 0.72 SMYS
3	t.p. / 1.40 or 0.56 SMYS
4	t.p. /1.40 or 0.44 SMYS

where: t.p. = test pressure

Since the mid-1950s, the pipeline industry in the U.S. had been sponsoring pipeline research under the auspices of the Pipeline Research Committee (PRC) of the American Gas Association. In 1968, the PRCI published Report No. L30050 titled: *Study of*

[2] CSA Standard Z183-1967, Oil Pipe Line Transportation Systems, Canadian Standards Association, June 1967

Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure[3].

The research study indicated that:

1. It is inherently safer to base the maximum allowable operating pressure on the test pressure, which demonstrates the actual in-place yield strength of the pipeline, than to base it on SMYS alone.
2. High pressure hydrostatic testing is able to remove defects that may fail in service.
3. Hydrostatic testing to actual yield, as determined with a pressure-volume plot, does not damage a pipeline.

The report specifically recommended that allowable operating pressures be set as a percentage of the field test pressure. In particular, it recommended that the allowable operating pressure be set at 80% of the test pressure when the minimum test pressure is 90% of SMYS or higher.

Although the report was circulated to the B31.8 Code Committee, the proposal to raise the operating limit to 80% SMYS was not adopted at that time in the U.S. because of uncertainty over the pending Federal Regulations that were under development by the Office of Pipeline Safety. (ASME B31.8 finally adopted this concept in the early 1990's).

No such uncertainties existed in Canada for the CSA Z184 Gas Pipe Line Code Committee, which had representation from the regulatory agencies. Indeed, the Vice-Chairman of the Code Committee was the representative from the National Energy Board.

The Z184 Committee had been closely following the research work in the U.S. and was convinced of the merits of the report. In 1972, the Committee approved the proposal to raise the operating limit for gas pipelines to 80% SMYS by a vote of 28-2.

While the limit of 80% SMYS for pipelines in Class Location 1 was based on the PRC Report[3], the limits for the other Class Locations were initially derived using the same percentage increase as for Class Location 1; i.e. 0.80/0.72 or 111%. Thus, the limits for Class Locations 2, 3 and 4 should have been 67%, 56%, and 44% SMYS, respectively. However, the limit for Class Location 2 was raised to 72%. The intent, simply, was to allow existing pipeline sections in Class Location 1 affected by a class location change to be upgraded for service in Class Location 2 without having to replace the affected section with thicker wall pipe or higher grade steel pipe.

With the publication of CSA Z184–1973, gas pipelines were allowed to operate at 80% SMYS. The significance of this change was recognized by the industry and, even before the 1973 edition of CSA Z184 was published, a major gas transmission company was already planning to hydrostatically retest some 1100 miles of its system to upgrade to a MAOP at 80% SMYS.

Canada does not maintain an incident database[4] similar to the U.S. and therefore the change in operating stress levels cannot be documented with incident data. No potential

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[3] Duffy, A.R., McClure, G.M., Maxey, W.A. and Atterbury, T.J., Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure, AGA Report No. L30050 (1968)

problems developed with the 0.80 design factor pipelines until the mid 1990's after 22 years of operation at the higher design factors. In 1996, the NEB became concerned about the near neutral stress corrosion cracking that had occurred on 22 oil and gas transmission pipelines and held a hearing to explore the problem and solutions to it. The NEB report concluded with regard to operating pressure:

> "In looking at the elements of an effective SCC management program, we also considered whether a reduction in operating pressure would be an effective way to deal with SCC on existing pipelines. As there is no clear evidence of a threshold level of pressure below which SCC will not initiate and grow, a pressure reduction will not prevent failures and will be very costly."

The report concluded that the most effective way of addressing the issue of SCC would be "through company-specific SCC management programs" that require the specific application to specific pipelines of the knowledge and best practices already developed across the industry.

No other problems have arisen in Canada and they continue to operate pipelines with the same design factors included in the 1973 CSA Code. The requirements discussed in this section are those in the current (2003) edition of CSA Z662. Table 8.1 of the current edition of the pipeline standard, CSA Z662-03, sets the maximum operating pressure for a gas pipeline in Class Location 1 as the lesser of the design pressure and the minimum strength test pressure achieved divided by 1.25. The CSA requires 100% SMYS pressure tests if a pipeline is to be operated at 80% SMYS and fracture control through requirements of pipe transition temperatures below the minimum operating temperature and fracture toughness levels to assure fracture initiation tolerance and fracture arrest.

The design pressure and the minimum strength test pressure are the only two parameters that specifically limit the MOP of a pipeline. While there are other design and material requirements (e.g., stress limitations, fracture control) related to a pipeline's operating pressure, they do not set a prescribed limit to the pipeline's MAOP.

Results of Recent PRCI Research

Recently, the Pipeline Research Council International (PRCI) completed a study[5] that examined the relative risk levels that would exist if an 80% SMYS design stress were applied to hypothetical existing lines. This study found that existing lines can tolerate increased stress levels but to achieve an acceptable risk level a considerable amount of data will be needed. The study also found that in a number of pipeline situations significant mitigation of the risk may be necessary if higher design factors are implemented. The study indicated that pipelines could be operated at a 0.80 design factor if an acceptable risk level is maintained.

[4] Canadian regulators (NEB and EUB) maintain two databases, but these are not readily accessible to the public, and the periodic reports that the boards issue do not make it possible to extract the necessary statistics relative to design factor. Neither of the databases goes back far enough to capture the 1973 changes

[5] Eiber, R.J., McLamb, M., and McGehee, W. B., Quantifying Pipeline Design at 72% SMYS as a Precursor to Increasing the Design Stress Level, GRI-00/0233, December, 2000.

Since the publication of the PRCI study, OPS issued Subpart O of Part 192, which applies to pipelines in HCA's. Rather than require an acceptable risk level for operation of pipelines at increased design factors, it seems appropriate to implement an integrity management plan such as required in ASME B31.8S or in Subpart O for all pipelines that are operated with a 0.80 design factor in a Class Location 1. If increased design factors are applied to Class Location 2 through 4, then these requirements could be modified for application in those class locations or other requirements developed.

Preliminary Assessment of Increased Design Factor to Existing Pipelines

The PRCI study concluded that if a 0.80 design factor is to be applied to existing Class Location1 gas pipelines a number of factors should be assessed such as:

- weld seam type,
- girth weld type and proportion of welds inspected ,
- fracture control provisions,
- wrinkle bends, and
- pipeline piggability.

Some of the older pipelines may require modification if an increased design factor is to be applied depending on the factors listed above or in Subpart O of Part 192 or ASME B31.8S.

Conclusions

1. **Prior Pipeline Operation in the U.S. Has Demonstrated Safe Operation of >0.72 Design Factor Pipelines.** Pipelines operating with design factors from 0.73 to 0.87 have shown through over 68,000 mile-years of operation from 1953 to 1979 that higher design factor pipelines can be safely operated.
2. **Integrity Management Strategies are Necessary for Safe Operation of Pipelines.** A pipeline in a Class Location 1 can be operated safely at 73-80% SMYS, provided that appropriate strategies are in place to address potential threats to pipeline integrity, which is not really different than for all pipelines.
3. **Low Stress Levels or Design Factor Does Not Assure Safety** - This review found that lower stress levels do not enhance pipeline safety and reliability with respect to the numbers of incidents.
4. **Review of a Number of Parameters is Suggested before Retrospective Application of Higher Design Factors.** A list of assessments has been presented to assist in application of higher design factors to older pipelines. Newer pipelines are anticipated to meet the industry consensus standards (e.g. ASME B31.8 or B31.8S).
5. **It Is Time to Take Advantage of the Improvements that Have Been Accomplished in Pipe Making, Line Construction, Welding Techniques and Inspection Techniques by Basing the Operating Pressure on the Test Pressure by Allowing a 0.80 Design Factor for Class Location 1 (with appropriate safeguards).** The PRCI supports the adoption of the suggested approach proposed herein.