List of Attachments

[illegible] 1:	R[illegible]rd Kupr[illegible]w[illegible]z CV
[illegible] 2:	Data Responses to TURN Data R DR 03, 08, 01(a), 07 and 12
[illegible] 3:	Data Responses to DRA Data Re DR 02, 04, 05 and 06
[illegible] 4:	ASME B31.8S-2004, Table 4, "Acceptable Prevention and Repair Methods," p
[illegible] 5:	John F. Kiefner and Michael J. Pressure Cycles on Gas Pipelines, 04/15/08, September 17, 2004.
[illegible] 6:	Kiefner & Associates, Inc. Letter from Mic Rosenfeld to Jane Yura, September Provided as response to CCSF_0
[illegible] 7: CONFIDENTI[illegible]	Hughes Report to PG&E Co., "Fi Evaluation, Radius of Influence for Rev 3, March 24, 2011, p. 7.
[illegible] 8:	Gas Research Institute, GRI-95/0101, "Final Re Remote and Automatic Main Line Assessment," July 1995, p. 74
[illegible] 9:	AGA White Paper, "Automatic Valve Shut-off And Remote Control Valves (RCV) On Nat Transmission Pipelines," March 25, 2
[illegible] 10:	Mark J. Stephens, C-FER Technologies, topical prepared for Gas Research Institute, Sizing High Consequence Areas Asso Natural Gas Pipelines," GRI-00/0189, October,
[illegible] 11: CONFIDENTI[illegible]	C-Fer Technologies letter to PG&E, C-FER PIR Formula to Alternative dated March 10, 2011.

12: CONFIDENTI	ENengineering Report prepared for PG&E, Survey of Operation Natural Gas on Automatic Valves," dated April
13:	Robert J Eiber Consultant Inc and Associates, "Review of Safety Consid Natural Gas in Pipe Block Valve Spacing,
14:	Evangelos Michalopoulos and Sandy Taslo Report, "Evaluation of Pipeline Prepared for Gas Research Institute, page 20
15:	Wesley B. McGehee, Maximum Allowable Ope Pressure (MAOP) Background and H for Gas Research Institute, revised 9
16:	PHMSA Workshop presentation to Advisory Committee, "Managing Challeng Pipeline Seam Welds and Improving Assessments and Recordkeeping," August slide 11 showing gas line Pipe 2010) by Seam Type including
17:	NTSB R-p r, d-. R-p r NTSB/P R-95/01, "P p-l - d-. R-p r, T-x E -r. Tr , C rp r N ur l G P p-l - Expl d F r- Ed , N-w J-r-y M r 23, 1994," d p-d J u ry 18, 1995, p. 5.

ATTACHMENT 1

Curriculum Vitae of Richard Kuprewicz

Curr□□ulu, V□)-.

R□□□) rd B. Kupr-w□□z

4643 192·d Dr NE
R-d, □. d, W(98074

T-l: 425-836-4041 (O□□□-)
E-,) □l: kupr-w□□z@□□, □) □□. -□

Pr□□□l-: (□pr-□d-. □&□(□□u) □□□ l. □, l □p-□) lz- □ g) □). d l□qu□d p□p-l□- □v-□□g) □&.,) ud□□g, r□k ,).) g-, -. □, □□□g, □&. □□ru□□&., d-□g., &p-r) □&., ,) □□.). □-, □r) □□g, SC(D(, l-) k d-□□□&., ,).) g-, -. □r-v□w, -, -rg-. □y r-□p&. □-,). d r-gul) □&ry d-v-l&p, -. □). d □&, pl□). □-. l □) v- □&. □ul□d □&r v) r□&u□l&□) l, □□) □). d □d-r) l) g-. □□, NGO□, □- publ□□,). d p□p-l□- □du□ry, -, b-r□&. p□p-l□- r-gul) □&., &p-r) □&.). d d-□g., w□□ p) r□□ul) r -, p□) □□□ &. &p-r) □&. □ u. u□u) lly □-. □□v-) r-) □&□□g□p&pul) □&. d-. □□y &r-. v□r&., -. □) l □-. □□v□y.

E, pl□y, -. □:

(□□u) □□□ l. □. **1999 – Pr-□-. □**

P□p-l□- r-gul) □&ry dv□□&r, □□d-. □□v-□□g) □&r,). d -xp-r□w□- □□&.) ll,) □r□r-l) □d □&g) □). d l□qu□d p□p-l□- □□□g, d-□g., &p-r) □&., ,) □□.). □-, r□k).) ly□□,). d,).) g-, -. □

P□□□□. : Pr-□d-. □
Du□□: > Full bu□□- □□r-□p&. □b□l□y
> T-□□. □□) l Exp-r□

(l) □k) (. v□l l. □. **1993 – 1999**

E. g□--r□g, pr&□ur-, -. □,). d □&. □□ru□□&. (EPC) &v-r□g□□&r v) r□&u□□l□. □□&. &□pr&du□□&. □) □□l□□□, r-□□g,). d □r). □p&r) □&. p□p-l□- d-□g. /&p-r) □&. □□ (l) □k).

P□□□□. : Pr&□- □□T-), □-) d-r
Du□□: > □-d pr&□- □□-. g□--r□gr&up
> R-v□w pr&□- □□d-□g. □
> P-r□&r, H) z) rd).) ly□□
> H(ZOP T-), l-) d-r
> (□□ur- r-gul) □&ry □&, pl□). □- □ p□p-l□-). d pr&□- □□□) □y,).) g-, -. □

(RCO Tr). □p□r) □□. (l) □k), l. □. **1991 - 1993**

Ov-r□-- Tr). □(l) □k) P□p-l□- Sy□□, (T(PS)). d &□-r (l) □k) p□p-l□-) □□- □□&r (r□&,) □r Exx&. V) ld-z-v-. □

P□□□□. : S-. □&r T-□□. □□) l (dv□□&r
Du□□: > (□□- □□&) ll (l) □k) &p-r) □&. □w□□p) r□□) l (r□& &w. -r□□p
> R-v□w,).) ly□-,) j&r (l) □k) p□p-l□- pr&j-□□□

(RCO Tr). □p□r) □□. C□. **1989 – 1991**

R-□p&. □bl- □&r □r) □g□pl). . □g, d-□g., g&v-r. , -. □□□r) □-,). d □&. □□ru□□&. &□. -w g) □ p□p-l□- pr&j-□□□,) □w-ll) □g) □p□p-l□-) □qu□□□&. /□&. v-r□&. □.

P□□□□. : M).) g-r G) □P□p-l□- Pr&j-□□□
Du□□: > Pr&j-□□,).) g-, -. □
> O□l p□p-l□- □&. v-r□&. □&g) □□r). □, □□□&.
> N-w d□□r□bu□&. p□p-l□- □□□) ll) □&.
> Full □r. k-y r-□p&. □b□l□y □&r . -w g) □□r). □, □□□&. p□p-l□-, □□lud□g FERC □□□g

□ð

<u>F□ur C□r. -r□P□p-l□- C□.</u> **1985 – 1989**

M) .) g- d &p- r) □&. □&□□rud- &□l) . d pr&du□□p□p- l□- □/□r, □) l□/b- r□□/) . k □r, □&p- r) □□g □ w- □□r. U.S. □□lud□g, r- gul) □&ry □&, pl□) . □- /□p□ll r- □p&. □- ,) . d □- l- □&, , u. □□) □&. □& SC(D(&rg) . □z) □&. □□upp&r□□g &p- r) □&. □.

P□□□□□. : V□□- Pr- □d- . □) . d M) .) g- r &□Op- r) □&. □
Du□□- □: > Full &p- r) □&.) l r- □p&. □b□l□y
> M) j&r □□p b- r□□ &p- r) □&. □
> N- w) □qu□□□&. □
> S- v- r) l □□&u□) . d , □l- □&□□&, , &. □) rr□r) . d pr□v) □ p□p- l□- □

<u>(r□□ Pr□du□□CQC K□l.</u> **1985**

Op- r) □&. □,) .) g- r &□. - w pl) . □) □qu□□□&. , . □lud□g ,) j&r □&g- . - r) □&. p&w- r g- . - r) □&. , w□□ □ull pr&□□□- . □r r- □p&. □b□l□y.

P□□□□□. : Pl) . □M) .) g- r
Du□□- □: > T-) , bu□ld□g &□. - w □) □l□y □□) □□) d b- - . □) l□.g
> Pl) . □d- □g. , &d□□□) □&. □) . d □r&ubl- □□&&□□g
> S- □□□g - xp- . □-) . d □) p□) l budg- □□, . □lud□g k- y g) □□upply . - g&□) □&. □
> M&d□□□) □&. &□□□-) , pl) . □, p&w- r g- . - r) □&. ,) . d - . v□r&. , - . □) l □&. □r&l□

<u>(r□□ Pr□du□□□C□</u> **1981 - 1985**

Op- r) □d R- □□- d Pr&du□□Bl- . d□g, S□&r) g-) . d H) . dl□g T) . k F) r, □,) □w- ll) □U□□l□y) . d W) □□- W) □r Tr-) □, - . □Op- r) □&. □&r □□- □□rd l) rg- □□r- □□- ry &. □□- w- □□□&) □□.

P□□□□□. : Op- r) □&. □M) .) g- r &□Pr&□- □□S- rv□- □
Du□□- □: > M&d- r. □z- r- □□- ry u□□l□□- □) . d □□&r) g- /bl- . d□g &p- r) □&. □
> D- v- l&p □ydr&□) rb&. pr&du□□bl- . d□, . □lud□g RFG□
> M&d□□□) □&. &□□□-) , pl) . □□, p&w- r g- . - r) □&. ,) . d - . v□r&. , - . □) l □&. □r&l□
> C&&rd□.) □d . - w ,) j&r □&g- . - r) □&. . □□) ll) □&. , 400 MW plu□

<u>(r□□ Pr□du□□□C□</u> **1977 - 1981**

C&&rd□.) □d □□&r□) . d l&. g-r) . g- &p- r) □&.) l) . d □) p□) l pl) . . □g,) . d ,) j&r - xp) . □□&. □&r □w& w- □□□&) □□r- □□- r□□.

P□□□□□. : M) .) g- r &□R- □□- ry Pl) . . □g) . d Ev) lu) □&.
Du□□- □: > E□□) bl□□□ , &. □□ly r- □□- ry v&lu, - □r□□pl) . □.
> D- v- l&p 5-y-) r r- □□- ry l&. g r) . g- pl) . □
> P- r□&r, - □&. &, □□) .) ly□□□&r r- □□- ry - . □) . □- , - . □□
> I□□u-) u□□&r□z) □&. □&r □) p□) l/- xp- . □- ,) j&r - xp- . d□ur- □

<u>(r□□ Pr□du□□□C□</u> **1973 - 1977**

Op- r) □□g Sup- rv□□&r) . d Pr&□- □□E. g□- - r □&r v) r□&u□,) j&r r- □□- ry □&, pl- x- □.

P□□□□□. : Op- r) □&. □Sup- rv□□&r/Pr&□- □□E. g□- - r
Du□□- □: > FCC C&, pl- x Sup- rv□□&r
> Hydr&□r) □k- r C&, pl- x Sup- rv□□&r
> Pr&□- □□- . g□- - r □□r&ug□&u□,) j&r . □□gr) □d r- □□- ry □, pr&v□g pr&□- □□y□ld) . d - . - rgy - □□□□- . □y

Qu) l□□□) □□. □:

Curr- . □ly □- rv□. g) □) , - , b- r r- pr- □- . □□g □□- publ□□&. □□- □d- r) l T- □□. □□) l H) z) rd&u□ □qu□d P□p- l□- S) □ □y S□) . d) rd□C&, , □□- (TH□PSSC),) □ □□. □□) l □&, , □□- - □) bl□□- d by C&. gr- □□ □&) dv□- PHMS(&. p□p- l□- □) □ □y r- gul) □&. □.
C&, , □□- , - , b- r□) r-) pp&□. □d by □□- S- □r- □) ry &□Tr) . □p&r□) □&. .

S- rv- d □- v- . y-) r□, □□lud- d p&□□&.) □ □□ □□) □r,) . , &. □□- W) □□□. g□&. S□) □ C□□z- . □ C&, , □□- &. P□p- l□- S) □ □y (CCOPS).
P&□□&. □) r-) pp&□. □d by □□- g&v- r. &r &□ □□- □) □ □&) dv□- □d- r) l, □□) □,) . d l&□) l g&v- r. , - . □□&. ,) □□r□r- l) □d □& p□p- l□- □) □ □y, r&u□□g, □&. □ru□□&. , &p- r) □&.) . d ,) □ □.) . □- .
S- rv- d &. Ex- □u□v- □ub□&, , □□-) dv□□. g C&. gr- □□) . d PHMS(&.) r- p&r□ □□) □□ul, □.) □d □□&. - w □d- r) l rul- □□&. □- r. □g D□□rlbu□&. I. □gr□y M) .) g- , - . □Pr&gr) , (DIMP) g) □ d□□rlbu□&. p□p- l□- □) □ □y r- gul) □&. □.

(□) r- pr- □- . □) □v- &□□□- publ□,) dv□- d □□- O□□- &□P□p- l□- S) □ □y &. pr&p&□- d . - w l□qu□d) . d g) □ □r) . □, □□□&. p□p- l□- □. □gr□y ,) .) g- , - . □rul- ,) k□g □&ll&w□g □□- p□p- l□- □r) g- d□ □ □ B- ll□g□) , , W) □□□. g□&. (1999)) . d C) rl□b) d, N- w M- x□& (2000).

M- , b- r &□C&. □r&l R&&, M) .) g- , - . □□&, , □□-) □□□□□. g PHMS(&. d- v- l&p, - . □&□p□p- l□- □) □ □y C&. □r&l R&&, M) .) g- , - . □(CRM) r- gul) □&. □.

C- r□□□d) . d - xp- r□. □- d H(ZOP T-) , □-) d- r) □□&□) □d w□□ pr&□- □□□) □ □y ,) .) g- , - . □) . d) ppl□□) □&. .

Edu□) □□. :

MB((1976)	P- pp- rd□- U. □v- r□□y, □&□(. g- l- □, C(
BS C□- , □□) l E. g□- - r□g (1973)	U. □v- r□□y &□C) l□&r. □) , D) v□, C(
BS C□- , □□ry (1973)	U. □v- r□□y &□C) l□&r. □) , D) v□, C(

Publ□□) □□. □ □. □□- Publ□□D□,) □ :

1. "(. (□□- □□, - . □&□F□r□□R- □p&. d- r R-) d□- □□ □&r P□p- l□- E, - rg- . □□ □ □ □□- S□) □ &□W) □□□. g□&. ," pr- p) r- d □&r □□- O□□- &□□- S□) □ F□r- M) r□□) ll, by H) . □&. E. g□- - r□l. □, Elw) y R- □-) r□□l. □,) . d (□□u□) □□□l. □,) . d d) □d Ju. - 26, 2001.

2. "Pr- v- . □□g P□p- l□- F) □lur- □," pr- p) r- d □&r □□- S□) □ &□W) □□□. g□&. J&□. □□- g□l) □v- (ud□□) . d R- v□w C&, , □□- ("J□(RC"), by R□□□) rd B. Kupr- w□z, Pr- □d- . □&□(□□u□) □□□l. □, d) □d D- □- , b- r 30, 2002.

3. "P□p- l□- □- N) □&.) l S- □ur□y) . d □□- Publ□□'□R□g□□- □&-K. &w," pr- p) r- d □&r □□- W) □□□. g□&. C□y) . d C&u. □y P□p- l□- S) □ □y C&. □&r□u, , by R□□□) rd B. Kupr- w□z, d) □d M) y 14, 2003.

4. "Pr- v- . □□g P□p- l□- R- l-) □- □," pr- p) r- d □&r □□- W) □□□. g□&. C□y) . d C&u. □y P□p- l□- S) □ □y C&. □&r□u, , by R□□□) rd B. Kupr- w□z, d) □d July 22, 2003.

5. "P□p- l□- I. □gr□y) . d D□r- □□(□□- □□, - . □,(□) y,) . '□P- r□p- □□v- ," pr- p) r- d □&r □□- P□p- l□- S) □ □y Tru□□by R□□□) rd B. Kupr- w□z, d) □d N&v- , b- r 18, 2004.

6. “Publ□□S) □□y) . d FERC’□ □NG Sp□ , W□) □C□□z- . □(r- . ’□B- □g T&ld,” j&□ □ly) u□□&r- d by R□□□) rd B. Kupr- w□□z, Pr- □□d- . □&□(□□u□) □□□ l. □, Cl□□&rd (. G&ud- y, Ou□r-) □□ C&&rd□) □&r MIT S-) Gr) . □C&ll- g- Pr&gr) , ,) . d C) rl M. W- □, - r, Ex- □u□v- D□r- □□&r P□p- l□ - S) □□y Tru□□, d) □d M) y 14, 2005.

7. “(S□, pl- P- r□p- □□v- &. Ex□- □□Fl&w V) lv- E□□ □□v- . - □□ □ G) □D□□□rbu□&. Sy□□ , S- rv□□- □□ - □,” pr- p) r- d □&r □□- P□p- l□ - S) □□y Tru□□by R□□□) rd B. Kupr- w□□z, d) □d July 18, 2005.

8. “Ob□- rv) □&. □&. □□- (ppl□□) □&. &□S,) r□P□gg□g &. Tr) . □, □□□&. P□p- l□ - □,” pr- p) r- d □&r □□- P□p- l□ - S) □□y Tru□□by R□□□) rd B. Kupr- w□□z, d) □d S- p□ , b- r 5, 2005.

9. “T□- Pr&p&□- d C&rr□b O. □□&r- Sy□□ , (. l. d- p- . d- . □(.) ly□□□,” pr- p) r- d □&r □□- C- . □r- □&r Publ□□l. qu□ry by R□□□) rd B. Kupr- w□□z, d) □d O□□&b- r 24, 2005.

10. “Ob□- rv) □&. □&. S) k□) l□ ll Tr) . □, □□□&. P□p- l□ - □,” pr- p) r- d □&r T□- W□ld S) l, &. C- . □r by R□□□) rd B. Kupr- w□□z, d) □d F- bru) ry 24, 2006.

11. “l. □r-) □□g M(OP &. U.S. G) □Tr) . □, □□□&. P□p- l□ - □,” pr- p) r- d □&r □□- P□p- l□ - S) □□y Tru□□by R□□□) rd B. Kupr- w□□z, d) □d M) r□□ 31, 2006. T□□□p) p- r w) □) l□& publ□□□- d □ □□- Ju. - 26) . d July 1, 2006 □□□u- □&□□□- O□l□& G) □J&ur.) l) . d □ □□- D- □ , b- r 2006 □□□u- &□□□- UK Gl&b) l P□p- l□ - M&. □□ly ,) g) z□- □

12. “(. l. d- p- . d- . □(.) ly□□□&□□□- Pr&p&□- d Bru. □w□□k P□p- l□ - R&u□ □ □ S) □ □J&□ , N- w Bru. □w□□k,” pr- p) r- d □&r □□- Fr□ . d□&□R&□kw&& d P) rk, by R□□□) rd B. Kupr- w□□z., d) □d S- p□ , b- r 16, 2006.

13. “C&, , - . □) ry &. □□- R□□k (.) ly□□□ □&r □□- Pr&p&□- d E, - r) Bru. □w□□k P□p- l□ - T□r&ug□ S) □ □J&□ , NB,” by R□□□) rd B. Kupr- w□□z, d) □d O□□&b- r 18, 2006.

14. “G- . - r) l Ob□- rv) □&. □O. □□- My□□&□) B- □□l. □r.) □&.) l P□p- l□ - S□) . d) rd,” pr- p) r- d □&r □□- P□p- l□ - S) □□y Tru□□by R□□□) rd B. Kupr- w□□z, d) □d M) r□□ 31, 2007.

15. “Ob□- rv) □&. □&. Pr) □□□) l □-) k D- □□□&. □&r Tr) . □, □□□&. P□p- l□ - □ – (. Expr- □ . □- d P- r□p- □□v- ,” pr- p) r- d □&r □□- P□p- l□ - S) □□y Tru□□by R□□□) rd B. Kupr- w□□z, d) □d (ugu□□30, 2007.

16. “R- □&, , - . d- d □-) k D- □□□&. M- □□&d□ □&r □□- K- y□&. - P□p- l□ - □ □□- V□□□□y &□□□- F &rdv□ll- (qu□□r,” pr- p) r- d □&r Tr) . □C) .) d) K- y□&. - □P. by R□□□) rd B. Kupr- w□□z, Pr- □□d- . □&□(□□u□) □□□ l. □, d) □d S- p□ , b- r 26, 2007.

17. “l. □r-) □□g MOP &. □□- Pr&p&□- d K- y□&. - X□ 36-l. □□ □qu□d Tr) . □, □□□&. P□p- l□ - ,” pr- p) r- d □&r □□- P□p- l□ - S) □□y Tru□□by R□□□) rd B. Kupr- w□□z, d) □d F- bru) ry 6, 2009.

18. “Ob□- rv) □&. □&. U. □□- d C&, ,) . d Dr□□□R□v- r F) □□S□- - □N& 1: W) □r U□) g- Op□&. □ □&r □□- □urr- . □M□ R- d&ub□V&l□) . & □□r-) □& □□- Dr□□□R□v- r O□l□T- r, □) l,” pr- p) r- d □&r C&&k l. l- □k- - p- r by R□□□) rd B. Kupr- w□□z, d) □d (pr□l 3, 2009.

19. “Ob□- rv) □&. □&. □□- K- y□&. - X□ O□l□P□p- l□ - DEIS,” pr- p) r- d □&r Pl) □ □Ju□□□- by R□□□) rd B. Kupr- w□□z, d) □d (pr□l 10, 2010.

20. "P(DD III & P(DD II R- ry Op&. &r C) .) d) . Bu, - . O) . d - K- y&. - X P p- l. - ," pr- p) r- d &r - N) ur) l R- &ur- D- . - C&u. l (NRDC) by R) rd B. Kupr- w z, d) d Ju. - 29, 2010.

21. "The State of Natural Gas Pipelines in Fort Worth," prepared for Richard B. Kuprewicz, President of Accufacts and Carl M. Weimer, Executive Di dated October, 2010.

22. "Accufacts' Independent Observations on the Chevron No. 2 Crude Oil Lake, Utah, by Richard B. Kuprewicz, 2011 dated January 30,

23. "Accufacts' Independent Analysis of New Proposed School Sites and Risks Pipeline," prepared for the Sylvania, Ohio School District, by Richard

24. "Accufacts' Report Concerning Related Issues to the 36 Natural Gas Pipeline and the Appleview, LLC Premises: 7009 and 7010," prepared for River Road, the North Bergen, Condominium Association Inc., by Richard B. Kuprewicz, dated February 2

□TT□CHMENT 2

Data □ð Responses □ð to □ð TURN □ □ð

□ð

DR □ Q03, 03, 01(a), □ 07 □ and 01 □ 12

PACIFIC GAS AND ELECTRIC COMPANY
Gas Pipeline Safety OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	TURN_005-03		
PG&E File Name:	GasPipelineSafetyOIR_DR_TURN_005-Q03		
Request Date:	September 14, 2011	Requester DR No.:	005
Date Sent:	September 29, 2011	Requesting Party:	The Utility Reform Network (TURN)
PG&E Witness:	Todd Hogenson	Requester:	Marcel Hawiger

QUESTION 3

Re: p. 2-12, lines 21-24:

a. Please identify the miles of transmission pipeline "identified for replacement" and the miles actually replaced as part of the GPRP by year for each year in which transmission pipe was included in the GPRP.
b. Please identify by year the expenditures on transmission pipeline replacement in the GPRP.

ANSWER 3

a. The miles of gas transmission pipeline identified for replacement in the GPRP program has varied based on program changes and information gathered on the pipeline segments. PG&E calculated an approximate baseline annual forecast of the miles of gas transmission pipeline to be replaced by the GPRP program by taking the total gas transmission mileage identified for replacement, and dividing it by the initial proposed program length, which calculates out to 23.2 miles/year (463 total miles reported in the 1988 and 1989 Annual GPRP Progress Reports divided by a initial program length of 20 years).

   The actual miles of gas transmission pipeline replaced as part of the GPRP by year is provided in GasPipelineSafetyOIR_DR_TURN_005-Q03Atch01.

b. The annual expenditures on gas transmission pipeline replacement in the GPRP are provided in GasPipelineSafetyOIR_DR_TURN_005-Q03Atch01.

TURN DR 05-03 [illegible] 01

G[illegible] Tr[illegible] GPRP

YE(R	GPRP ([illegible]$u) l M[illegible] R[illegible]pl) [illegible]d	GPRP ([illegible]$u) l [illegible]($ [illegible])
1985	14.4	$14.4
1986	15.3	$17.7
1987	28.5	$28.7
1988	19.0	$20.5
1989	27.0	$31.6
1990	19.1	$12.1
1991	28.0	$18.3
1992	12.5	$14.7
1993	10.0	$12.4
1994	8.8	$12.9
1995	17.7	$8.8
1996	19.8	$25.0
1997	19.8	$6.1
1998	19.5	$6.8
1999	9.8	$4.8
T[illegible]$ l	269.2	$234.8

PACIFIC GAS AND ELECTRIC COMPANY
Gas Pipeline Safety OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	TURN_008-01		
PG&E File Name:	GasPipelineSafetyOIR_DR_TURN_008-Q01		
Request Date:	October 19, 2011	Requester DR No.:	008
Date Sent:	October 27, 2011	Requesting Party:	The Utility Reform Network (TURN)
PG&E Witness:	Todd Hogenson	Requester:	Marcel Hawiger

QUESTION 1

In the segment database spreadsheet provided in response to TURN 004-03 Atch. 1, please provide a revised spreadsheet that also includes additional columns with the following information for each segment number:

a. HCA – yes or no
b. Class location
c. PIR
d. Decision Tree box for that segment
e. If the segment is included in the Implementation Plan, an identifier specifying whether the segment is included in Ph 1 or Ph 2 of the Implementation Plan.
f. If the segment is included in Phase 1 of the Implementation Plan, a reference identifying which project contains that segment (i.e. the line no. and/or order no. used in Table 2 or Table 3 of the workpapers to ch. 3).
g. Wall thickness

Please note that items a-d correspond to information provided for each project in the workpapers to ch. 3. TURN presumes these data are contained in the master database used to produce the response to TURN 004-03Atch01. If there are any questions concerning this request, please contact TURN prior to the due date of the response.

ANSWER 1

Please see attachment, GasPipelineSafetyOIR_DR_TURN_008-Q01Atch01. This excel file contains a list of every gas transmission pipe segment and the specific attributes for each segment that were used or developed in the preparation of the Pipeline Modernization Program within the Pipeline Safety Enhancement Plan (PSEP).

a. HCA information can be found within Column Y.

b. Class location information can be found within Column V.

c. PIR (Potential Impact Radius) calculations can be found within Column Z.

d. Decision tree box for each segment can be found within Column AD.

e. Phase 1 proposed activities for Strength testing and Replacement can be found in Column AE (Project Type). Blanks imply no recommended strength test or replacement in Phase 1; see column AD to determine if future strength testing or replacement is proposed for Phase 2.

f. Each pipe segment with a recommended Phase 1 action (strength testing or replacement) is assigned a unique PSRS ID Project Number column AK, and Project Order Number columns AS, AT, AU, AV depending on action (replacement, strength testing, ILI retrofitting, ILI inspection) which can be cross referenced back to Chapter 3, Table 3 or 4.

g. Wall Thickness can be found within Column J.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Pipeline Safety OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	TURN_008-03		
PG&E File Name:	GasPipelineSafetyOIR_DR_TURN_008-Q03		
Request Date:	October 19, 2011	Requester DR No.:	008
Date Sent:	October 28, 2011	Requesting Party:	The Utility Reform Network (TURN)
PG&E Witness:	Todd Hogenson	Requester:	Marcel Hawiger

Please note that the attachment to this response contains sensitive personal information pertaining to PG&E employees, such as employee names and identifications. For these reasons only, the attachment to this response is submitted to TURN pursuant to a Non-Disclosure Agreement. The dissemination of employee information contained in the attachment to this response raises privacy concerns. Therefore, PG&E believes that such information should remain confidential and not be subject to public disclosure.

QUESTION 3

Re. PG&E Testimony, p. 3B-20:

a. Please describe PG&E's "Engineering Condition Assessment" process and all of the steps involved in that process.
b. Please provide any testimony or workpaper references explaining the ECA procedure or showing any outcome or result of an ECA process.
c. Please provide all documents (including but not limited to internal manuals, memoranda, etc.) describing the ECA procedure.
d. Has PG&E utilized the ECA historically to determine the need for pipeline replacement? If yes, please provide a sample ECA report and any standard operating procedures.

ANSWER 3

a. PG&E does not have an Engineering Condition Assessment (ECA) procedure in place for the Pipeline Safety Enhancement Program, but is working to develop an acceptance criterion to assess the condition of the Decision Tree referenced antiquated or abnormal pipe joints, girth welds, angle points, or other fittings. PG&E plans to work with experts in piping metallurgy and ground movement to develop tools and methodology to assist in quantifying pipeline strains for defined ground displacement hazards. The request in this proceeding is to fund the development and implementation of an ECA procedure to assess the condition of, and in some situations removal and replacement of, non-standard fittings.

b. Work paper WP-1308 describes the request to fund the engineering development of the ECA procedure. Justification for this analysis is discussed in the Justification document, Attachment 3B, on pages 3B-18 and 3B-19. The concept for the process is to study the condition of non-pipe components or non-prescriptive acceptance code fittings, bends, or other pipeline features to determine their fitness for continued safe service in the presence of ground movement (ranked by likelihood and/or applied strain to the pipe), where the outcome of the assessment would either result in a determination that the line/fitting is good for safe service or should be replaced..

   The Pipeline Modernization Decision Tree and data available in PG&E's Geographic Information System (GIS) does a good job generally of identifying the correct safety enhancement work for line pipe, but lacks specific detail on fittings, pipe bends, or other "point" features in the pipeline. The purpose of this ECA Project is to ensure these unique pipeline features are analyzed to a modern acceptance criteria for safe service. ECA will identify replacement opportunities of abnormal pipe fittings, short joints, and angle points that may not be fit for service in areas where the pipe is likely to experience outside forces.

c. Provided to TURN pursuant to a Non-Disclosure Agreement is the confidential PG&E Risk Management Instruction (RMI) 06, provided as GasPipelineSafetyOIR_DR_TURN_008-Q03Atch01-CONF, which describes the use of an Engineering Critical Assessment (a condition assessment is a more broad assessment than a critical variable assessment, but the assessment process is the same) to evaluate whether or not a seam related manufacturing threat has become unstable when a pipeline's pressure exceeds a five year high. The ECA process is discussed in both ASME B31.8S 2010 and the Canadian Transmission Pipeline Safety Code for use when prescriptive blanket standards for acceptability do not exist or have not been met but a more detailed analysis may prove features are fit for service.

d. No. As shown in the answer to part (c) above, PG&E has an ECA process in place that yields Integrity Management assessment methods, but not specifically pipe replacement.

PACIFIC GAS AND ELECTRIC COMP ANY
Gas Pipeline Safety OIR
Rulemaking 11 -02-019
Data Response

PG&E Data Request No.:	TURN_010-01(a)		
PG&E File Name:	GasPipelineSafetyOIR_DR_TURN_010-Q01(a)		
Request Date:	December 1, 2011	Requester DR No.:	010
Date Sent:	December 9, 2011	Requesting Party:	The Utility Reform Network
PG&E Witness:	Todd Hogenson	Requester:	Marcel Hawiger

QUESTION 1A

PG&E provided data on Gas Transmission pipeline replacement mileage and actual spending by year for 1985-1999 in response to DR 05-Q3Atach01. Likewise, the Risk Management Annual Reports provided as attachments to DR 01-10 provided mileage data for 2004-2006. TURN could not locate in the GPRP or the RMA reports any data on transmission replacement mileage for 2000-2003, or for 2007-2010.

a. Please provide data on annual "actual miles replaced" and "actual replacement expenditures" for 2000-2003 and 2007-2010.

ANSWER 1A

a. The annual "actual miles replaced" and "actual replacement expenditures" for 2000-2003 and 2007-2010 are below.

Year	Miles Replaced	Expenditures
2000	6.9	$7,791,488
2001	2.7	$4,282,355
2002	6.4	$8,127,475
2003	3.2	$6,674,761
2007	4.44	$10,937,800
2008	1.3	$6,140,373
2009	3.8	$13,314,284
2010	1.7	$10,926,640

PACIFIC G AS AND ELECTRIC COMP ANY
Gas Pipeline Safety OIR
Rulemaking 11 -02-019
Data Response

PG&E Data Request No.:	TURN_010-07		
PG&E File Name:	GasPipelineSafetyOIR_DR_TURN_010-Q07		
Request Date:	December 1, 2011	Requester DR No.:	010
Date Sent:	January 6, 2012	Requesting Party:	The Utility Reform Network
PG&E Responder:	Todd Hogenson	Requester:	Marcel Hawiger

QUESTION 7

Please provide the mileage and pipeline type replaced each year that is associated the 1997-2003 capital expenditure data provided in TURN 02-02.

ANSWER 7

See PG&E's response to TURN_010-Q06, which further defines data provided in response to TURN_002-Q02. PG&E's response to TURN 002-Q02 contained three tables:

- Table a - Pipeline Inspection, which contains annual expenditures to retrofit and inspect pipelines. This data is a subset of Table b.
- Table b - Pipeline Integrity Management, which contains annual expenditures recorded within MWC 98, Pipeline Integrity Management.
- Table c – Pipeline Repair and Replacement, which contains annual expenditures recorded within MWC 75, Pipeline Transmission Reliability/Safety.

All pipeline replacements discussed in the response are transmission pipe. Provided below are three tables that include Capital expenditures and miles of pipe installed/replaced from 1997 – 2003, as reported in MWCs 98 and 75.

Pipeline Inspection
ILI Retrofit portion of MWC 98

	1997	1998	1999	2000	2001	2002	2003
Capital Expenditures ($ Million)	0.0	0.0	0.0	0.1	6.7	6.2	5.1
Miles of Pipe Replaced	0	0	0	0	0.1	0.2	0

Pipeline Integrity Management
All Recorded Costs and Miles MWC 98

	1997	1998	1999	2000	2001	2002	2003
Capital Expenditures ($ Million)	0.0	0.0	0.0	0.1	6.7	6.2	10.6
Miles of Pipe Replaced	0	0	0	0	0.1	0.2	0.5

Pipeline Reliability & Safety
All Recorded Costs and Miles MWC 75 + (MWC 14 GPRP carry-over 2000-2003)

	1997	1998	1999	2000	2001	2002	2003
Capital Expenditures ($ Million)	8.7	8.4	4.5	18.3	12.5	13.7	19.0
Miles of Pipe Replaced	1.4	1.4	0.7	6.2	4.4	4.8	3.3

In 2000, PG&E transitioned from the Gas Pipeline Replacement Program (GPRP) to a Pipeline Risk/Integrity Management Program. Several pipeline replacement projects that were in progress as of January 2000 were completed as part of MWC 14, GPRP. The expenditures and pipeline mileage are included in the table above.

PACIFIC G AS AND ELECTRI C COMP ANY
Gas Pipeline Safety OIR
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Data Response

PG&E Data Request No.:	TURN_012-01		
PG&E File Name:	GasPipelineSafetyOIR_DR_TURN_012-Q01		
Request Date:	December 14, 2011	Requester DR No.:	012
Date Sent:	January 6, 2012	Requesting Party:	The Utility Reform Network (TURN)
PG&E Witness:	Todd Hogenson	Requester:	Marcel Hawiger

QUESTION 1

PG&E provided data on Gas Transmission pipeline replacement mileage and actual spending by year for 1985-1999 in response to DR 05-Q3Atach01. Likewise, the Risk Management Annual Reports provided as attachments to DR 01-10 provided mileage data for 2004-2006. TURN could not locate in the GPRP or the RMA reports any data on transmission replacement mileage for 2000-2003, or for 2007-2010.

Please provide data on annual "actual miles replaced" and "actual replacement expenditures" for 2004-2006.

ANSWER 1

See PG&E's response to GasPipelineSafetyOIR_DR_TURN_010-Q06 and GasPipelineSafetyOIR_DR_TURN_010-Q07, which further clarify data provided in response to GasPipelineSafetyOIR_DR_TURN_002-Q02.

Provided below are two tables that include Capital expenditures and miles of pipe installed/replaced from 1997 – 2003, as reported in MWCs 98 and 75.

Pipeline Integrity Management
All Recorded Costs and Miles MWC 98

	2004	2005	2006
Capital Expenditures ($ Million)	$12.1	$19.3	$15.3
Miles of Pipe Replaced	0.4	0.5	0.4

Pipeline Reliability & Safety
All Recorded Costs and Miles MWC 75

	2004	2005	2006
Capital Expenditures ($ Million)	$12.1	$17.3	$15.0
Miles of Pipe Replaced	3.9	5.0	3.3

Please note that miles of pipeline installed by year within MWC 98 and 75 was retrieved from PG&E's Geographic Information System (GIS). Most station piping is not currently shown in PG&E's GIS. Station piping information currently is complete only on our paper maps and station drawings. A review of the hundreds of paper maps and station drawings was not performed.

In addition, PG&E defines and assigns gas transmission capital projects to several Major Work Categories (MWCs) depending on the project driver. They are:

MWC	Definition
26	G Trans - New Business
73	G Trans - New Capacity
75	G Trans - Pipeline Reliability/Safety
83	G Trans - Work Requested by Others
84	G Trans - Gas Gathering
91	Power Plant Metering
98	Pipeline Integrity Management
76	G Trans - Station Reliability/Safety

The data provided in response to this data request concerns only MWCs 98 and 75, which is where the majority of the gas transmission pipeline replacement and risk reduction focused work occurred for the years 2000-2006. However, some pipeline replacement can and will occur within nearly every MWC. This makes it difficult to quantify actual miles of pipeline replaced and replacement expenditures within the context of this Data Request and prior data requests in which TURN has asked for similar data. We have not quantified or reported total miles replaced and/or retired within all MWCs.

ATTACHMENT 3

Data □ð Responses □ð to □ð DRA □□ð Data □ð Requests:

DR □ð 02, □ð 04, □ð 05 □ð and □ð 06

PACIFIC G AS AND ELECTRIC COMP ANY
Gas Pipeline Safety OIR
Rulemaking 11 -02-019
Data Response

PG&E Data Request No.:	DRA_045-03		
PG&E File Name:	GasPipelineSafetyOIR_DR_DRA_045-Q03		
Request Date:	December 16, 2011	Requester DR No.:	045 (TCR-18)
Date Sent:	January 6, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Todd Hogenson Sumeet Singh	Requester:	Tom Roberts

QUESTION 3

PG&E's response to DRA 26-Q14 seems to indicate that PG&E has three separate data fields regarding pressure testing for each segment (see responses to subpart b, j, and k).

a. Which of these fields is used to implement the following decision tree criteria: 1H, 2F, and 3A? Provide three separate responses.

b. Provide a summary of the differences between these three fields.

c. Describe how each of these three fields was used to establish the PSEP.

d. Explain why Sub-J and Sub_J62411 have Y or N data only, but MAOPrec430 has four potential values (see TCR 15-7).

ANSWER 3

a. As mentioned in PG&E's response to DRA_045-Q01 and DRA_038-Q01, through the development of the PSEP program and subsequent filing, PG&E added several columns of additional data to the PSEP database (each time there was an update) while not deleting the original data for cross referencing and archiving purposes. Data column "Sub_J" (GasPipelineSafetyOIR_DR_DRA_026-Q14 b) is obsolete.

   The Decision Tree, in all Sub-Part J decisions (1H, 2F, and 3A) uses the data within "MAOPrec430" and "Sub_J62411" per the query logic provided in DRA_038-Q05.

b. The field "Sub_J" was populated in early February 2011 as a means to take a preliminary look at the amount of pipe segments meeting these criteria. The "MAOPrec430" data is the final upload from the MAOP validation team into the PSEP database describing the status of the completeness search of PG&E records of pressure tests for all method 1 HCA (see CFR 192.903) pipe segments. The "Sub_J62411" data is the determination of a valid pressure test, used by the

SB_GT&S_0597292

Decision Tree decisions 1H, 2F, and 3A. The "Sub_J62411" data was populated by calculating the ratio of the recorded test pressure to the MOP relative to the class location. For class locations 1 and 2, this needed to be equal to or greater than a 1.25 to yield a Y for yes, and for class locations 3 and 4, this needed to be equal to or greater than a 1.5 to yield a Y for yes; otherwise, it was populated with an N for no. A special letter " T", was used to document where a previous test was conducted at a pressure level that does not meet today's standards. A "T" was treated as a No in the decision tree. All Y data meeting the recorded pressure test to MOP ratio requirements also needed to be shown as "complete," blank, or "partial" in the "MAOPrec430" column to receive a Y; otherwise, they were ruled as an N for not meeting the Sub Part J requirements. The data provided in the January 3, 2011 Geographic Information System (GIS) data set was used as the basis for this calculation of test pressure over MOP, unless something was provided by MAOP validation, which would supersede the GIS data.

c. As previously discussed, "Sub_J" was not used. "MAOPrec430" is a download of completeness of the pressure test records on April 30, 2011 from the MAOP validation team into the PSEP database. The "Sub_J62411" is the determination of a valid Sub Part J test used in the Decision Tree queries.

d. As previously discussed, these are different data sets with different meanings. "Sub_J" data was not used. "MAOPrec430" data is a listing of completeness of pressure test records for pipe segments (complete, partial, incomplete, or blank). "Sub_J62411" calculates test pressure to MOP ratio for pipeline class code requirements coupled with the "MAOPrec430" data, as discussed above, resulting with responses - Y for yes, N for No, if a Sub Part J test has been conducted.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Pipeline Safety OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	DRA_045-04		
PG&E File Name:	GasPipelineSafetyOIR_DR_DRA_045-Q04		
Request Date:	December 16, 2011	Requester DR No.:	045 (TCR-18)
Date Sent:	January 9, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Todd Hogenson Sumeet Singh	Requester:	Tom Roberts

QUESTION 4

PG&E's response to DRA 26-Q14b defined the data field "Sub_J". The following refer to this response:

a. When was this field populated?

b. How was this field populated?

c. Where is this information stored and updated. Provide the database name, the software it uses, and the PG&E IT system on which it is run and stored.

d. Please confirm if the following interpretation is correct, or correct as needed to make it an accurate statement: A "Y" value in this field indicates that a pressure test was performed, that it had a duration of 1 hour minimum, that PG&E verified all information required by 49 CFR 192.517, and that this verified information is cataloged and accessible.

e. Does a "Y" value in this field indicate that PG&E has verified the segment has met all requirements of 49 CFR 192, subpart J?

f. Explain why a minimum 1 hour test duration is used, particularly since %SMYS for each segment is known.

g. Could this field have a "Y" value if an 8 hour test was required per subpart J, but PG&E's records indicated a 1 hour duration?

h. Does PG&E track the information required if a 4 hour test duration is justified for each segment, per 192.505(e)? If so, how? If not, why not?

i. Is the PSEP filed on Aug. 26, 2011 based upon this data?

j. When was this field last updated?

ANSWER 4

The "Sub_J" data is obsolete, not maintained, and was not used for the PSEP filing; please see PG&E's response to DRA-038-Q01 and PG&E's Q3 of this data request. Therefore, the response to this data request discusses the "Sub_J62411" column, which was used to support the PSEP filed on Aug. 26, 2011

a. June 24th, 2011 is the date that the field "Sub_J62411" was completely incorporated into the PSEP database for subsequent use in the Decision Tree queries to create the PSEP filing.

b. The "Sub_J62411" data was populated by calculating the ratio of recorded test pressure to the MOP relative to class location. For Class locations 1 and 2, this needed to be equal to or greater than a 1.25 to yield a Y for yes, and for class locations 3 and 4, this needed to be equal to or greater than a 1.5 to yield a Y for yes; otherwise it was populated with an N for no. All Y data needed to also be shown as "complete," blank, or "partial" in the "MAOPrec430" column to receive a Y; otherwise, they were given an N for no. A special letter "T" was used to document where a previous test was conducted at a pressure level that does not meet today's standards. A "T" is treated as a No in the decision tree analysis.

c. The "Sub_J62411" data is a calculated value populated in the PSEP database as described above. Updates for this data are being captured and stored in the pipeline features lists (PFL) created by the MAOP validation team. Manual reference between the PSEP database and PFLs will occur and any subsequent updates will be made to the PSEP database at the project validation phase of project engineering. This information will be shared with the CPUC semi-annually, as described in Chapter 8 of direct testimony at page 14, Progress Reporting.

d. The interpretation is not correct. The "Sub_J" data field is obsolete, not maintained, and was not used for the PSEP filing. The "Sub_J62411" data was populated by calculating the ratio of recorded test pressure to the MOP relative to class location. As described in part (b) above, for class locations 1 and 2, this needed to be equal to or greater than a 1.25 to yield a Y for yes, and for class locations 3 and 4, this needed to be equal to or greater than a 1.5 to yield a Y for yes; otherwise it was populated with an N for no. All Y data needed to also be shown as "complete," blank, or "partial" in the "MAOPrec430" column to receive a Y; otherwise, they were given an N for no. A "Complete" or "Partial" in the "MAOPrec430" field for a method 1 HCA pipe segment indicates that pressure test records contain the following four elements: 1) name of operator, 2) test pressure, 3) test duration and 4) test medium for the full length of a "complete" segment or a fraction of the length of a "partial" segment, that a minimum test duration of 1 hour is shown, and that this information is cataloged and verified by the MAOP verification team. These four pieces of information are listed in 192.517(a) (1), (2), (3), and (4). Please see PG&E's March 15, 2011 Report on Records and MAOP Validation in R-11-02-019 for more information. For a non-method 1 HCA segment, a "Y" indicates that the January 3, 2011 PG&E GIS database indicates that the pressure test to MOP ratio meets the

PSEP class location requirements, 1.25 and 1.5 respectively. Verification of pressure test records for non-method 1 HCA pipe will not be complete until 2013.

e. See the response to part (d) above.

f. Per CPUC Rulemaking Decision 11-06-017, issued on June 9, 2011, on page 31, the CPUC Ordered, "… pressure tests conducted prior to the effective date of General Order 112, one hour is the minimum acceptable duration for a pressure test". CPUC GO 112 dated July 1, 1961 required a minimum test duration of 1 hour. On November 12th, 1970 with the enactment of the Federal Pipeline Regulations 49 CFR Part 192, other test durations in excess of 1 hour were required for pipelines operating at or above 30% Specified Minimum Yield Strength (SMYS).

g. If the pressure test on the example segment was conducted prior to November 12, 1970 (date on which the CPUC adopted 49 CFR 192 resolution G-1499), then yes this condition could occur. If the pressure test was conducted after November 12, 1970, then this situation should not occur.

h. The test duration is evaluated as part of the Pipeline Features List (PFL) preparation. This detailed review of the pipeline can determine if a 4 hour test was performed and valid.

i. Yes.

j. Please see response to part (a) above.

PACIFIC G AS AND ELECTRIC COMP ANY
Gas Pipeline Safety OIR
Rulemaking 11 -02-019
Data Response

PG&E Data Request No.:	DRA_045-05		
PG&E File Name:	GasPipelineSafetyOIR_DR_DRA_045-Q05		
Request Date:	December 16, 2011	Requester DR No.:	045 (TCR-18)
Date Sent:	January 6, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Todd Hogenson Sumeet Singh	Requester:	Tom Roberts

QUESTION 5

PG&E's response to DRA 26-Q14k defined the data field "Sub_J62411". The following refer to this response:

a. Is the difference between these this field and "Sub_J" only the date the data was evaluated? If not, specify the differences referring to the questions and responses to TCR18-4 above.

b. Is the PSEP filed on Aug. 26, 2011 based upon this data?

c. When was this field last updated?

ANSWER 5

a. The difference is that "Sub_J" was derived by calculating the ratio of the recorded test pressure to the MOP using the data in PG&E's Geographic Information System (GIS) as of January 3, 2011 only. The "Sub_J62411" data is the updated data set that takes into consideration the MAOP validation work, uploaded by the "MAOPrec430" data column. Where the "MAOPrec430" data was not populated, a blank entry, the "Sub_J62411" data uses the same calculation preformed for the "Sub_J" data column.

b. The PSEP filing is based on the "Sub_J62411" data.

c. The "Sub_J62411" data was finalized on June 24, 2011.

PACIFIC G AS AND ELECTRIC COMP ANY
Gas Pipe line Safety OIR
Rulemaking 11 -02-019
Data Response

PG&E Data Request No.:	DRA_045-06		
PG&E File Name:	GasPipelineSafetyOIR_DR_DRA_045-Q06		
Request Date:	December 16, 2011	Requester DR No.:	045 (TCR-18)
Date Sent:	January 6, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Todd Hogenson Sumeet Singh	Requester:	Tom Roberts

QUESTION 6

PG&E's response to DRA 26-Q14j defined the data field "MAOPrec430". The following refer to this response:

a. Does a "complete" value in this field mean the data review is complete, that a pressure test was completed, or both?

b. If a "complete" value in this field indicates that a pressure test was completed, what are the criteria for determining that the test is complete? Refer to questions in TCR 18-4 above and the subpart J requirements.

c. Define a "partial mileage" value in this field.

d. Does a "partial mileage" value in this field indicate that complete data has been verified per a and b above for a portion of the segment footage, but not all of the footage?

e. Is the PSEP filed on Aug. 26, 2011 based upon this data?

f. When was this field last updated?

ANSWER 6

a. A "complete" value means that the assessment of the available pressure test reports indicate that the installed pipe is tested and the pressure test reports meet the applicable standards at the time the test was conducted. The table in testimony on page 3B-5 shows the strength test factors for the historic applicable standards.

b. PG&E deemed "complete" pressure test records to be those that contain the following four elements: 1) name of operator, 2) test pressure, 3) test duration, and 4) test medium. If the initial review of the records did not include all four of these elements, additional analysis was required to determine if other sources of information were available to substantiate the prior pressure test. 49 C.F.R. §

192.517(a) includes three additional recordkeeping elements: "(5) Pressure recording charts, or other record of pressure readings; (6) Elevation variations, whenever significant for the particular test; and (7) Leaks and failures noted and their disposition." With respect to "(5) Pressure recording charts, or other record of pressure readings," the STPR contains a field for contemporaneous entry of the pressure reached, which is "[an]other record of pressure readings." Wherever available, PG&E confirmed that the pressure reached on the pressure chart correlated with the pressure entered on the STPR. Elevation variations, and leaks and failures and their disposition, would not logically exist for every pressure test, but only those where elevation variations were significant for the test or where leaks were found. PG&E documented these elements when applicable and available.

c. Partial mileage means that pressure test records have not been able to confirm that the entire pipeline segment has been tested. The details of the exact location of this un-tested pipe could not be substantiated during the initial evaluation period. However, additional analysis is being performed as part of the Records Verification and MAOP Validation Project based on performing additional job related documents such as construction detail drawings, sketches and job notes to confirm that all relevant portions of the pipeline have been pressure tested.

d. Yes.

e. Yes.

f. The last update of the MAOP validation effort into the PSEP program prior to the August 26, 2011 filing was from April 30, 2011.

PACIFIC G AS AND ELECTRIC COMP ANY
Gas Pipeline Safety OIR
Rulemaking 11 -02-019
Data Response

PG&E Data Request No.:	DRA_045-07		
PG&E File Name:	GasPipelineSafetyOIR_DR_DRA_045-Q07		
Request Date:	December 16, 2011	Requester DR No.:	045 (TCR-18)
Date Sent:	January 6, 2012	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Sumeet Singh	Requester:	Tom Roberts

QUESTION 7

PG&E filed a report on MAOP validation dated March 15, 2011 in R.11-02-019. At page 13, the report shows that of the pipelines analyzed and installed before 7/1/1961, at least 31% were pressure tested.

a. What was the justification for performing these tests?

b. Is there any further breakdown of when pressure tests were performed as a function of installation date?

c. When did PG&E first pressure test newly constructed or repaired lines?

d. Provide PG&E requirement documents describing the requirements for performing these tests.

e. Provide PG&E procedures describing how these tests were performed.

f. Were these tests funded by PG&E ratepayers or PG&E shareholders?

g. Provide documents which state that PG&E shareholders paid to have these tests performed, or that PG&E would not request funding from ratepayers, if applicable.

ANSWER 7

a. Pressure tests were, and are, a means to confirm or test the strength of pipeline segments. PG&E believes that after adoption of American Society of Mechanical Engineers (ASME) standard ASA B31.1.8-1955, PG&E's practice was to follow ASA B31.1.8-1955, including pre-service testing.

b. Additional breakdown of pressure tests as a function of installation date is available for the approximately 723 miles of pipeline segments installed before July 1, 1961 that were part of the 1,805 miles of Class 3 and Class 4 and Class 1 and Class 2 HCA segments that were the subject of PG&E's March 15, 2011 report on Records and MAOP Validation.

SB_GT&S_0597300

c. The earliest date identified on a pressure test report for newly constructed or repaired pipelines is 1954; however, there were no state or federal regulatory requirements to perform pressure tests prior to 7/1/1961.

d. Pressure tests were performed in accordance with ASA B31.1.8 – 1955 and no additional PG&E standards have been located for this era.

e. Please see response to part (d) above.

f. The testing was part of the pipe installation costs and, therefore, would have been funded by ratepayers.

g. Please see response to part (f) above.

ATTACHMENT 4

ASME B31.8S-2004, Table 4, "Acceptable Threat Prevention and Repair Methods," p 22

Table 4 Acceptable Threat Prevention and Repair Methods (Cont'd)

	Third-Party Damage			Corrosion Related		Equipment				Incorrect Operation	Weather Related			Manufacture		Construction				O-Force	Environment
Prevention, Detection, and Repair Methods	TPD(IF)	PDP	Vand	Ext	Int	Gask/Oring	Strip/BP	Cont/Rel	Seal/Pack	IO	CW	L	HR/F	Pipe Seam	Pipe	Gweld	Fab Weld	Coup	WB/B	EM	SCC
Repairs																					
Pressure reduction	. . .	X	. . .	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	X	X	X	X	. . .	. . .	X
Replacement	. . .	X	X	X	X	X	X	X	X	. . .	X	X	X	X	X	X	X	X	X	X	X
ECA, recoat	. . .	. . .	. . .	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	. . .	. . .	. . .	. . .	. . .
Grind repair/ECA	. . .	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	X	X	X	. . .	. . .	. . .	X
Direct deposition weld	. . .	. . .	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .
Type B, pressurized sleeve	. . .	X	X	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	X	X	. . .	. . .	X
Type A, reinforcing sleeve	. . .	X	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	. . .	. . .	. . .	. . .	X
Composite sleeve	. . .	. . .	. . .	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .
Epoxy filled sleeve	. . .	X	X	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	X	X	X	X	X	. . .	. . .
Mechanical leak clamp	. . .	. . .	. . .	X	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .

GENERAL NOTE: The abbreviations found in Table 4 relate to the 21 threats discussed in para. 5. Explanations of the abbreviations are as follows:

Cont/Rel = Control/Relief Equipment Malfunction
Coup = Coupling Failure
CW = Cold Weather
EM = Earth Movement
Ext = External Corrosion
Fab Weld = Defective Fabrication Weld
Gask/Oring = Gasket or O-Ring
Gweld = Defective Pipe Girth Weld
HR/F = Heavy Rains or Floods
Int = Internal Corrosion
IO = Incorrect Operations Company Procedure
L = Lightning
PDP = Previously Damaged Pipe (delayed failure mode)
Pipe = Defective Pipe
Pipe Seam = Defective Pipe Seam
SCC = Stress Corrosion Cracking
Seal/Pack = Seal/Pump Packing Failure
Strip/BP = Stripped Thread/Broken Pipe
TPD(IF) = Damage Inflicted by First, Second, or Third Parties
Vand = Vandalism
WB/B = Wrinkle Bend or Buckle

ATTACHMENT 5

John F. Kiefner and Michael J. Rosenfeld, "Effects of Pressure Cycles on Gas Pipelines," GRI-04/0178, September 17, 2004.

GRI-04/0178

EFFECTS OF PRESSURE CYCLES ON GAS PIPELINES

FINAL REPORT

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Process Performance Improvement Consultants, LLC
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and
Gas Research Institute
Contract No. 8749

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September 17, 2004

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The objective of this study was to determine whether or not gas pipelines have a significant degree of exposure to failure from seam defects that could become enlarged by pressure-cycle-induced fatigue. If there is a potential problem in this respect, then knowing the conditions and times over which defect growth becomes significant, a pipeline operator can prevent failures by carrying out timely pipeline integrity assessments. In this study, times to failure were computed for worst-case hypothetical seam defects that would have barely survived a hydrostatic test to 100 percent of SMYS and subsequently subjected to the pressure-cycle histories of typical gas pipelines. The predicted times to failure ranged from 170 years to more than 400 years, indicating that in most circumstances, gas pipelines are not at significant risk of failure from the pressure-cycle-induced growth of seam defects that may exist after a hydrostatic test because the times to failure for this mode of crack growth are much longer than the expected useful life of a typical gas pipeline. Therefore, there is no need, in general, to conduct periodic integrity assessments of gas pipelines from the standpoint of pressure-cycle-induced fatigue in seams.

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Research Summary

Title:	Effects of Pressure Cycles on Gas Pipelines
Contractor:	Kiefner & Associates, Inc.
Principal Investigators:	John F. Kiefner and Michael J. Rosenfeld
Report Period:	January 2004 to September 2004
Objectives:	The purpose of this project is to establish the degree to which natural gas pipelines are susceptible to the threat of fatigue crack growth at initial defects in longitudinal seams as a result of normal operating pressure cycles.
Technical Perspective:	The threat of fatigue crack growth in longitudinal seam flaws due to the effects of pressure cycles has been recognized in some liquid pipelines but prior to this study had not been evaluated for gas pipelines.
Technical Approach:	The fatigue crack growth life of postulated seam flaws were estimated using fracture mechanics principles, considering initial hydrostatic test levels and representative operating pressure histories gathered from actual gas pipelines.
Results:	Natural gas pipelines were determined not to be susceptible to fatigue crack growth in longitudinal seams due to the effects of pressure cycles within the expected lifetime of the facility if the pipeline had been hydrostatically tested to reasonably high levels typically observed in the gas pipeline industry.
Project Implications:	A one-time hydrostatic test to a reasonably high level would be sufficient to assure that a natural gas pipeline would not be susceptible to the effects of pressure cycle fatigue on flaws in longitudinal seams. Periodic retesting or reassessment to mitigate this threat is therefore unnecessary.
Project Manager:	Charles E. French, P.E.

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EXECUTIVE SUMMARY

The objective of this study was to determine whether or not gas pipelines have a significant degree of exposure to failure from defects that could become enlarged by pressure-cycle-induced fatigue. If there is a potential problem in this respect, then knowing the conditions and times over which defect growth becomes significant, a pipeline operator can prevent failures by carrying out timely pipeline integrity assessments. Failures from defects that have been enlarged by pressure-cycle-induced fatigue have occurred on prior occasions in liquid-petroleum-products pipelines and crude-oil pipelines though no such failure has been observed in a gas pipeline. The absence of such occurrences in gas pipelines possibly may be attributed to the fact that gas pipelines are exposed to significantly less aggressive pressure cycling than liquid pipelines. However, prior to this study, a systematic comparison of the relative exposures of liquid and gas pipelines to pressure-cycle-induced fatigue had not been made.

In this study, pressure-cycle histories of three typical gas pipelines were compared to the pressure-cycle history of a liquid pipeline known to have aggressive pressure cycles. Aggressive pressure cycles can lead to service failures from fatigue crack growth within 5 to 10 years after a hydrostatic test to 1.39 times the maximum operating pressure if seam defects exist that are just the right size to barely survive the test. The primary bases for comparisons were the predicted times to failure for worst-case hypothetical defects subjected to the different pressure histories. These comparisons revealed times to failure for the hypothetical seam defects that ranged from 170 years to more than 400 years when the defects that would have barely survived a hydrostatic test to 100 percent of SMYS were subjected to the typical gas-pipeline pressure histories. In contrast, they revealed times to failure as short as 5 years when the defects were subjected to the typical liquid-pipeline pressure history. These results show that in most circumstances, gas pipelines are not at significant risk of failure from the pressure-cycle-induced growth of longitudinal seam defects that may exist after a hydrostatic test. The times to failure for this mode of crack growth are much longer than the expected useful life of a typical gas pipeline. Therefore, there is no need, in general, to conduct periodic integrity assessments of gas pipelines from the standpoint of pressure-cycle-induced fatigue in seams.

EFFECTS OF PRESSURE CYCLES ON GAS PIPELINES

by

John F. Kiefner and Michael J. Rosenfeld

BACKGROUND

The service demands for products transported through pipelines are inherently non-steady. As a result, operating pressure levels vary from time to time. Variations in operating pressure amount to variations in the hoop stress level in the pipeline, and it is widely recognized that stress fluctuations can cause metal fatigue that could eventually lead to the failure of the structure in service. Generally, the fatigue life of a properly-designed structure that is reasonably free of defects is quite long. Typically, millions of normal service-stress fluctuations are required for a failure to occur. In a pipeline, even in liquid petroleum products pipeline, the number of very large stress cycles (i.e., pressure cycles) is usually on the order of tens to hundreds of cycles in a year, so one might expect that the potential for a pressure-cycle-induced fatigue failure in any pipeline would be insignificant in the absence of longitudinally-oriented defects. Indeed, that is the case. A previous PRCI study[(1)] showed that the number of large pressure cycles required to cause a defect-free pipe to fail was in the range of 600,000 to 2,000,000 cycles with a stress range equal to one-half of the specified minimum yield strength (SMYS) of the pipe material (see Table 1). When one considers the actual pressure spectra for even the most aggressively cycled pipelines, it is clear that pipelines would be expected to endure thousands of years of service before a defect-free pipe would exhibit a failure from pressure-cycle-induced fatigue. Experience in the form of actual service failures verifies that such failures have occurred only where a significant pre-existing defect had become enlarged by fatigue-crack growth[(2-5)].

The problem of failures from defects that have been enlarged by pressure-cycle-induced fatigue has surfaced on prior occasions in liquid-petroleum-products pipelines and crude-oil pipelines. Longitudinal seam defects such as hook cracks and mismatched plate edges adjacent to ERW seams and rail shipment fatigue cracks in such pipelines have exhibited pressure-cycle-induced crack growth and failures on several occasions[(2-5)]. The authors are unaware of any such cases of failures in gas pipelines, and it is suspected that the reason for the absence of such failures is that typical gas-pipeline pressure-cycle spectra are far less aggressive than those of typical liquid-pipeline pressure-cycle spectra. Comparisons of typical spectra for gas and liquid pipelines are presented herein that show this to be the case.

The objective of this study was to determine whether or not gas pipelines have a significant degree of exposure to failure from defects that could become enlarged by pressure-cycle-induced fatigue. If so, it is of great importance from the standpoint of pipeline integrity to know the ranges of operating conditions and the periods of time over which this exposure could develop. If there is a potential problem in this respect, then knowing the conditions and times over which defect growth becomes significant, a pipeline operator can prevent failures by carrying out timely pipeline integrity assessments. The expectation is that such assessments will identify growing defects so that they can be repaired or removed before they reach sizes that will cause failures at normal operating stress levels.

PRESSURE-CYCLE SPECTRA

Operating pressure spectra (pressure levels as a function of time, in other words, operating pressure histories) were received from three gas pipeline operators. For comparison, we also examined an operating pressure spectrum for a typical liquid pipeline. Gas pipeline operating histories for time periods of a year or more of operation for 30 pipeline discharge sections were received. A liquid-pipeline operating history from our archives as well as our "benchmark" cycles* were used for comparison. It was originally the intent of this study to specifically address operation of gas storage facilities. We were unable to obtain pressure records from representative gas storage facilities in time to be included in the study, but we believe that the methods used and conclusions derived are applicable to such facilities.

It should be noted that we eventually narrowed the family of gas pipeline cycles to three spectra. This was done for a variety of reasons. For one, not all of the gas pipeline spectra were considered meaningful. In several cases, the operating spectra consisted of only the daily high

* We have compiled four pressure-cycle spectra (shown in Appendix A) that represent the fatigue crack growth effects of actual random stress fluctuations in pipelines that have experienced service failures from pressure-cycle-induced fatigue. The categories are based on observed times to failure after a hydrostatic test. By comparing the times to failure for a given pipeline pressure history to those associated with our benchmark spectra, we can classify the fatigue potential of the pressure history as very aggressive, aggressive, moderate, or light.

and low pressures. Comparisons between these and identical spectra that were also provided at hourly sample rates within the same period of time demonstrated that daily high and low spectra do not adequately capture all important pressure cycles. Hourly pressure readings show significantly richer pressure cycle content, and one hour is thought to represent an adequate sample rate. (We have observed a similar issue when conducting pressure-cycle fatigue susceptibility studies for liquids pipelines, but the relevant sample intervals are much shorter. For a liquid pipeline, a recording interval of 1 hour is usually not adequate to capture all of the significant cycles. Pressure sample rates for a liquid pipeline often must be at least every minute, and in some pipelines, every 15 seconds[*].) We have looked at the concept of collecting pressure-cycle data for gas pipelines at intervals longer than 1 hour. Our analysis of the three representative spectra considered in the report indicates that recording only a maximum and minimum level for a 24-hour period, for example, will conceal a significant number of relevant cycles. We believe that sampling intervals for gas pipelines should not exceed 1 hour and that the technology for capturing cycles at intervals smaller than 1 hour is readily available. Therefore, we believe that a longer sampling interval should not be used in a risk assessment of a gas pipeline for fatigue.

Another reason why certain operating histories were not useful was that some closely related systems had nearly identical pressure histories which led essentially to duplicates of the spectra. Yet another reason was that a spreadsheet contained pressure data in the form of active links to another spreadsheet that was not made available. In any case the pressure data supplied to us were culled to three operating spectra that we believe are sufficiently unique and detailed to be usable, and these three were analyzed further.

It is noted that pressure spectra (i.e., pressure versus time histories) do not easily lend themselves to fatigue analysis where it is necessary to have a fairly precise definition of a "cycle". For the purpose of fatigue analysis a "closed" cycle is assumed to consist of an

[*] This fact provides a preliminary clue to our finding that gas pipelines are exposed to significantly less aggressive pressure cycling than liquid pipelines. This is not surprising when one considers the difference between hydraulic and pneumatic pressurization. Pressure change in a liquid can be rapid and large amplitude because a small volume change leads to a significant pressure change. In contrast, a very large volume change is required to effect a significant-amplitude pressure change in a gas. In practical terms, when a liquid pipeline pump is shut off, the pressure drops quickly to the static-head pressure. In this manner, liquid pipelines frequently experience pressure-amplitude changes ranging from near-zero levels to their maximum operating pressures. By comparison, shutting down a gas compressor generally leaves a gas pipeline at a relatively high pressure. The pressure level in a gas pipeline usually cannot get anywhere near zero unless a significant volume of gas is discharged from the pipeline.

excursion from an initial pressure to another value of pressure (either higher or lower than the initial pressure) followed a return to the initial pressure level. In a random pressure spectrum, an excursion from one level of pressure to another is seldom followed immediately by a return to the initial level. In other words in an actual spectrum the pressure may go up from P_0 to a higher level, P_1, and then drop back to a level, P_2, that is somewhere between P_0 and P_1 after which the pressure goes to P_3 that is lower than P_0. A unique definition of a "closed" cycle is not readily apparent for this sequence. As a large number of such cycles accumulate, however, it becomes possible to "pair" certain maximum pressures with appropriate minimum pressures to define closed cycles consisting of maximum and minimum values that are separated from one another in time. A number of cycle-counting schemes are used by analysts to pair appropriate peaks and valleys in a spectrum to arrive at a set of cycles. Some of these are described in an ASTM standard(6). One of these called "rainflow" cycle-counting is the technique we prefer and use in our analyses.

CRACK-GROWTH ANALYSES

The growth of defects by fatigue can often be characterized by means of the "Paris-Law" approach(7) where the natural logarithm of the amount of crack growth per cycle of stress is proportional to the natural logarithm of the change in stress intensity factor that characterizes the particular cycle of stress. The Paris-Law crack-growth model is usually written as $da/dN=C(\Delta K)^n$, where "da" is the increment of crack growth per load cycle "dN", ΔK is the range of cyclic crack-tip stress-intensity associated with the given load step (i.e., stress cycle), and "C" and "n" are material crack-growth properties. The application of this kind of approach to pipelines is described in Reference 8. One of the approaches described in this document involves using a prior hydrostatic test to establish a representative family of defects (all having failure pressures equal to the hydrostatic test pressure), using a computer program to "grow" these defects (by numerically integrating the Paris-Law equation), and establishing the times required to grow each of the representative defects to a size that will fail at the maximum operating pressure within the pressure spectrum. The values of "C" and "n" (the crack growth rate constants) sometimes can be determined by fatigue crack-growth testing, or by benchmarking against a fatigue failure where the initial and final flaws and operating history are known. Crack-growth rate constants also have been published in the literature. One such rate is recommended for the analysis of steels by API Recommended Practice 579[9]. API RP 579 suggests using C = 8.6E-19 (for a stress intensity factor given in psi-root-inch units) and n = 3. We have chosen to use these constants herein because much of what we are presenting is a relative analysis where the effect of these constants essentially washes out of the comparisons. It should be noted, however, that when an absolute time to failure is needed, it is advisable to obtain, if possible, the constants that are applicable to the particular operating environment. The operating environment at the crack interface can have a large effect on the crack growth rate and on the time to failure.

Over a period of years we have observed and analyzed a number of liquid pipelines that have exhibited one or more failures from pressure-cycle-induced fatigue. From these experiences we have compiled four sets of one-year-long pressure spectra that seem to best represent the actual operating pressure spectra that led to the single or multiple fatigue-related failures. These "benchmark" cycles were initially published in Reference 10, but we later reassessed them and reissued them as they appear in Reference 8. The four categories of cycles are referred to as "very aggressive", "aggressive", "moderate" and "light". We will compare both typical liquid and gas pipeline pressure cycles to these benchmark cycles herein to show the relative aggressiveness of the typical cycles in both types of pipelines.

COMPARISONS OF PRESSURE CYCLES

The three gas-pipeline pressure histories that we consider to be the best candidates for analysis are shown in Figures 1-3. The first of these, shown in Figure 1 represents a 422-day period of operation that embodies a maximum pressure of 888 psig (not necessarily the maximum operating pressure, MOP, or the maximum allowable operating pressure, MAOP) and a minimum pressure of 38 psig. Note that the 38 psig minimum appears only once in the 422-day period. The next lowest pressure is a little over 450 psig and all other minimums exceed 500 psig. The second spectrum for a gas pipeline is shown in Figure 2. This spectrum represents a 365-day period of operation that embodies a maximum pressure of 794 psig and a minimum pressure of 65 psig (the latter appears only once). The next lowest pressure is about 170 psig and it too occurs only once. All other minimums exceed 550 psig. The third spectrum for a gas pipeline is shown in Figure 3. This spectrum represents a 365-day period of operation that embodies a maximum pressure of 782 psig and a minimum pressure of 182 psig (the latter appears only once). The next lowest pressure is about 200 psig and it too occurs only once though for an extended period of time. All other minimums exceed 400 psig.

The liquid-pipeline pressure history that we have chosen as being representative of the mid-range of aggressiveness is shown in Figure 4. This spectrum represents a 137-day period of operation that embodies a maximum pressure of 723 psig and a minimum pressure of 0 psig. Unlike the minimums in the gas pipelines discussed above, however, the zero pressure level appears repeatedly, and the number of large-amplitude cycles in this pipeline is clearly much greater than the one or two large cycles in each of the three gas pipelines.

As noted previously, pressure-versus-time histories such as those shown in Figures 1-4 need to be resolved into pressure cycles. We noted that we do this by rainflow cycle-counting. Once the cycles are defined and counted in this manner, they can be restated as pressure ranges, and that makes the four spectra easy to compare. Such a comparison is shown in Figure 5. One item to note is that the basis for Figure 5 is one-year's worth of cycles for each pipeline. Thus, the numbers of cycles in each range of rainflow-counted cycles for the 422-day history and for the 137-day history had to be "normalized" to be plotted on Figure 5 (i.e., multiplied by 365/422 in the first instance and by 365/137 in the second instance). Compared on this basis, the liquid pipeline has many, many more large-amplitude cycles than any of the gas pipelines.

COMPARISONS OF TIMES TO FAILURE

Another way to compare the relative effects of pressure cycles for the four pipelines is to use the cycles to calculate times to failure for the four pipelines. To do that we need to make sure that the stress ranges, not the pressure ranges, are comparable since it is actually the change in stress intensity factor the drives the crack growth. While the maximum pressures in the four pipelines seem to differ somewhat (they range from 723 psig to 888 psig), it is not too hard to visualize that all four pipelines could be comprised of the same pipe material (i.e., same diameter, same wall thickness, same grade of material). Therefore, to put the pipelines on the same stress basis, and to thoroughly disguise the sources of the pressure cycles, we chose to treat the cycles as if they applied to a pipeline comprised of 24-inch-OD, 0.289-inch-wall, Grade X52 material. The 100-percent-of-SMYS pressure level for this material is 1,252 psig and the 72-percent-of-SMYS pressure level is 901 psig. We established the initial defect sizes for our time-to-failure calculations on the basis of nine different defect-length/depth combinations that all have a predicted failure pressure of 1,252 psig (100 percent of SMYS) by reason of having just barely survived a pre-service hydrostatic test of the pipeline to that level. We then used our in-house computer program, PIPELIFE, which numerically integrates the Paris Law equation to determine the times to failure for each of the nine defects for each of the four different pressure spectra.

The results of the PIPELIFE calculations are summarized in Table 2. The minimum times to failure for the three gas pipelines range from 170 to over 400 years while that for the liquid pipeline is slightly over 5 years. This illustrates the fact that the effects of pressure cycles typically experienced by gas pipelines are far less significant than the effects of those typically experienced by a liquid pipeline.

Another way to illustrate the fact that gas pipelines do not have a significant level of exposure to pressure-cycle-induced fatigue, is to compare the typical gas pipeline cycles to the "benchmark" cycle-aggressiveness scale described in Reference 8. The benchmark levels of aggressiveness of the pressure cycles for liquid pipelines are shown in Table 3. The spectra for these cycles are comprised of blocks of cycles as shown in Appendix A. These blocks of cycles give predicted times to failure that are consistent with actual experience in liquid pipelines. The very aggressive cycles produce predicted times to failure that are consistent with those observed in circumstances where pressure-cycle-induced fatigue failures have occurred in times shorter than two years after a hydrostatic test[2] . The aggressive cycles produce times to failure that are consistent with those observed in circumstances where failures have occurred within five to ten years after a hydrostatic test. The moderate cycles produce times to failure that are consistent with those observed in circumstances where failures have occurred within ten to twenty years after a hydrostatic test. The light cycles produce times to failure that are consistent with those observed in circumstances where failures have occurred more than twenty years after a hydrostatic test. It is important to note that the benchmark pipelines were comprised of Grade X52 pipe. Thus, the stress ranges given in Table 3 are meant to be applied only to that grade of pipe even though they are categorized by SMYS ranges.

The gas pipeline aggressiveness analysis was accomplished by comparing the fatigue lives associated with the spectra provided to us by gas pipeline operators to those associated with the pressure cycles listed in Table 3. We used these four spectra, keying the maximum operating pressure to 72 percent of SMYS for the hypothetical 24-inch-OD, 0.289-inch-wall, X52 pipe material to calculate times to failure. The starting defect sizes were again those that would barely survive a hydrostatic test to 1,252 psig. The resulting times to failure (for the liquid-pipeline-simulating benchmark cycles not the actual gas pipeline pressure cycles) are shown in Table 4. As seen in Table 4, the very aggressive cycles produce a life as short as 0.87 year, the aggressive cycles produce a life as short as 3.43 years, the moderate cycles produce a life as short as 8.82 years, and the light cycles produce a life as short as 21.14 years. Because the actual pressure cycles for the gas pipelines as shown in Table 2 result in predicted fatigue lives ranging from 170 to 420 years, it is clear that the effects of typical gas pipeline pressure cycles on pipeline integrity are practically insignificant. It is reasonable to believe that these types of cycles could never cause defects that had survived a hydrostatic test to a pressure level well above the operating pressure to grow to failure in service within the conceivable life of a typical gas pipeline. In contrast the times to failure estimated for the typical liquid pipeline (shown in Table 2) are only slightly longer than those produced by the "aggressive" benchmark cycles and significantly shorter than those produced by the "moderate" benchmark cycles. This finding would lead us to conclude that the hypothetical liquid pipeline is subjected to aggressive pressure cycles. Therefore, it is exposed to a significant risk of failure from pressure-cycle-induced enlargement of existing defects. Consequently, the operator needs to periodically reassess its integrity at an appropriate interval to assure that any significantly enlarged defect is repaired before it becomes large enough to fail in service. It should be reasonably clear that no such periodic reassessments are necessary for the typical gas pipeline.

Note that the aggressiveness comparisons described above are independent of the crack growth rate constants "C" and "n". The same relative comparisons would result even if a different set of constants were to be used (provided that they are also used to calculate the times to failure for the cases involving the actual gas pipeline pressure cycles).

There are some circumstances where a gas pipeline could have more exposure to pressure-cycle-induced fatigue than the above calculations indicate. One such circumstance could exist if the pipeline were to be exposed to a much more aggressive environment from the standpoint of corrosion-fatigue. The effect of a corrosive environment can be simulated in terms of the value of “C”. The value we used was based on tests conducted in laboratory air environments. A more aggressive value could exist for a pipeline buried in a ground-water environment where external defects might become exposed in areas where the external coating had failed. For example, if the environment were four times as aggressive as laboratory air, the representative “C” value would equal 3.44E-18 instead of 8.6E-19. The effect would be a shortening of the predicted times to failure by a factor of four. In this event Gas Pipeline No. 1, which was shown to have a minimum predicted time to failure of 170 years would now have a minimum predicted time to failure of 43 years even though the “aggressiveness” of its pressure cycles would be exactly the same as before in comparison to the benchmark cycles. The worst-case laboratory-generated crack growth rates for line pipe in extreme environments were said to reduce times to failure obtained in laboratory air by a factor of 4[11]. However, the experiences with actual service failures in liquid pipelines suggest that the effective environments are no where near that aggressive. In fact, the effective crack growth rates in some cases have been found to be more like the rate that we used based on API RP 579.

The other circumstance where pressure-cycle-induced fatigue could become a significant threat to a gas pipeline consists of any case where a defect is present or is created that is already much larger than one that could have survived an initial pre-service hydrostatic test to a pressure level of 100 percent of SMYS. For example, we recalculated the times to failure for Gas Pipeline No. 1 using test pressure levels of 991 psig (79.2 percent of SMYS or 1.1 times the maximum operating pressure of 901 psig) and 1126 psig (90 percent of SMYS or 1.25 times the maximum operating pressure of 901 psig). Formerly, we had based the calculations on a test pressure level of 1,252 psig (100 percent of SMYS). The minimum time to failure calculated on the basis of the 991-psig test was 24 years, and the minimum time to failure calculated on the basis of the 1126-psig test was 76 years. In contrast, on the basis of the 1,252-psig test, the minimum time to failure was 170 years. This shows that the risk of pressure-cycle-induced fatigue can be dismissed if and only if the pipeline has been subjected to a reasonably high-pressure hydrostatic test. Therefore, it would seem that eliminating the risk of failure from pressure-cycle-induced fatigue crack growth of defects that can survive an initial hydrostatic test of a pipeline requires that the test pressure level must be at least 1.25 times the maximum operating pressure.

CONCLUSION

The results of our assessment of the effects of typical gas pipeline pressure cycles on pipeline integrity show that in most circumstances, gas pipelines are not at significant risk of failure from the pressure-cycle-induced growth of original manufacturing-related or transportation-related defects. Therefore, there is no need, in general, to conduct periodic integrity assessments of gas pipelines from the standpoint of pressure-cycle-induced fatigue.

While the risk of a failure in a gas pipeline from pressure-cycle-induced fatigue is expected to be insignificant in most cases, it is relatively easy for an operator to assess the risk for a given segment. In this respect, it is a good idea for an operator to consider the test-pressure-to-operating-pressure ratio and the pressure-cycle spectrum of HCA-affected segments as part of the risk-assessment process. If the risk is insignificant, the operator needs only to reassess the pressure cycles from time to time to make sure the situation does not change. In the unlikely event that the pressure cycles are sufficiently aggressive to create a potential problem within the useful life of the pipeline, an integrity assessment may have to be carried out at an appropriate time.

In the unlikely event that an operator detects a need to perform such an assessment, no fatigue-crack-growth model we know of lends itself to simple closed-form solutions when the spectra are comprised of random-amplitude cycles. A numerical integration scheme is required in such cases because hundreds of calculations must be done successively. Therefore, anyone wishing to conduct an analysis of this type would have to purchase commercially available software to do so or write his own computer program that performs the necessary calculations. The concepts embodied in such a program have been discussed in this report and in many references and texts. With the software, a trained technician or engineer can do the analysis.

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Table 1. Results of Pressure-Cycle Tests on Defect-Free Pipe

					Cycles to Failure for Various Pressure Ranges				
Sample No.	**Yield Strength, psi**	**Ultimate Tensile Strength, psi**	**Applied Stress Range, 46% UTS, psi(2)**	**Applied Pressure Range, psi(1)**	**Cycles to Failure, Test Pressures(3)**	**50% SMYS Pressure Range(4)**	**25% SMYS Pressure Range(4)**	**Pipe Geometry**	**Grade and Classification**
1	49,720	73,180	33,662 (80% SMYS)	100-1,090	347742	2,278,962	36,463,392	12.75 inches x 0.188 inch	Grade X42, ERW
2	51,000	72,000	33,120 (79% SMYS)	100-1,076	107372	669,144	10,706,299	12.75 inches x 0.188 inch	Grade X42, ERW
3	50,700	63,800	29,348 (70% SMYS)	100-1,250	369181	1,418,246	22,691,932	12.75 inches x 0.250 inch	Grade X42, ERW
4	54,200	76,400	35,144 (84% SMYS)	100-1,478	271651	2,163,956	34,623,297	12.75 inches x 0.188 inch	Grade X42, seamless
5	44,500	69,000	31,740 (69% SMYS)	100-1,190	437471	1,586,593	25,385,493	12.75 inches x 0.250 inch	Grade X46, ERW

(1)Because of set-ups on the pumping unit, the minimum pressure applied to the test samples was 100 psi.
(2)Percentage of the applied stress relative to the specified minimum yield strength for the respective pipe grade.
(3)Data presented based upon actual test results.
(4)Calculated number of cycles obtained using Miner's Rule and a fourth-order relationship between stress and cycles to failure. The following equation was employed in the calculation.

$$N_B = N_A * \left(\frac{\Delta P_A}{\Delta P_B} \right)$$

Table 2. Times to Failure in Years For Each Pipeline

Pipeline	Length of defect in inches followed by depth-to-thickness ratio of defect								
	0.90	**1.37**	**1.84**	**2.39**	**3.09**	**4.08**	**5.55**	**7.67**	**10.41**
	0.9	**0.8**	**0.7**	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.1**
Gas 1	187.29	170.96	173.28	187.15	217.35	298.28	>500	>500	>500
Gas 2	451.99	413.99	419.99	451.99	>500				
Gas 3	443.99	403.99	403.99	439.99	>500				
Liq. 1	5.62	5.15	5.25	5.63	6.39	8.58	14.81	33.95	100.21

Table 3. Annual Pressure (Hoop Stress*) Cycle Spectrum
(Number of Cycles in Each Stress Group)

Percent SMYS	Very Aggressive	Aggressive	Moderate	Light
72%	20	4	1	0
65%	40	8	2	0
55%	100	25	10	0
45%	500	125	50	25
35%	1000	250	100	50
25%	2000	500	200	100
Total	**3660**	**912**	**363**	**175**

*These stress ranges are listed in terms of SMYS for convenience. It should be noted, however, that they were derived from experience on X52 materials. Because actual stress range, not %SMYS, determines time to failure, the aggressiveness analysis treats the pipeline being assessed for aggressiveness as though it were X52 even if it is comprised of another grade of material. The actual grade is used when actual times to failure are calculated.

Table 4. Times to Failure in Years For Each Level of Cycle Aggressiveness

Level of Cycle Aggressiveness	Length of defect in inches followed by depth-to-thickness ratio of defect								
	0.90	**1.37**	**1.84**	**2.39**	**3.09**	**4.08**	**5.55**	**7.67**	**10.41**
	0.9	**0.8**	**0.7**	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.1**
Very Agg.	0.93	0.87	0.87	0.89	1.11	1.46	2.64	6.31	18.68
Aggressive	3.75	3.37	3.43	3.75	4.37	6.07	10.87	25.60	76.43
Moderate	9.63	8.82	8.88	9.63	11.37	15.62	28.07	66.10	197.86
Light	23.25	21.14	21.42	23.17	27.25	37.50	67.42	158.93	476.14

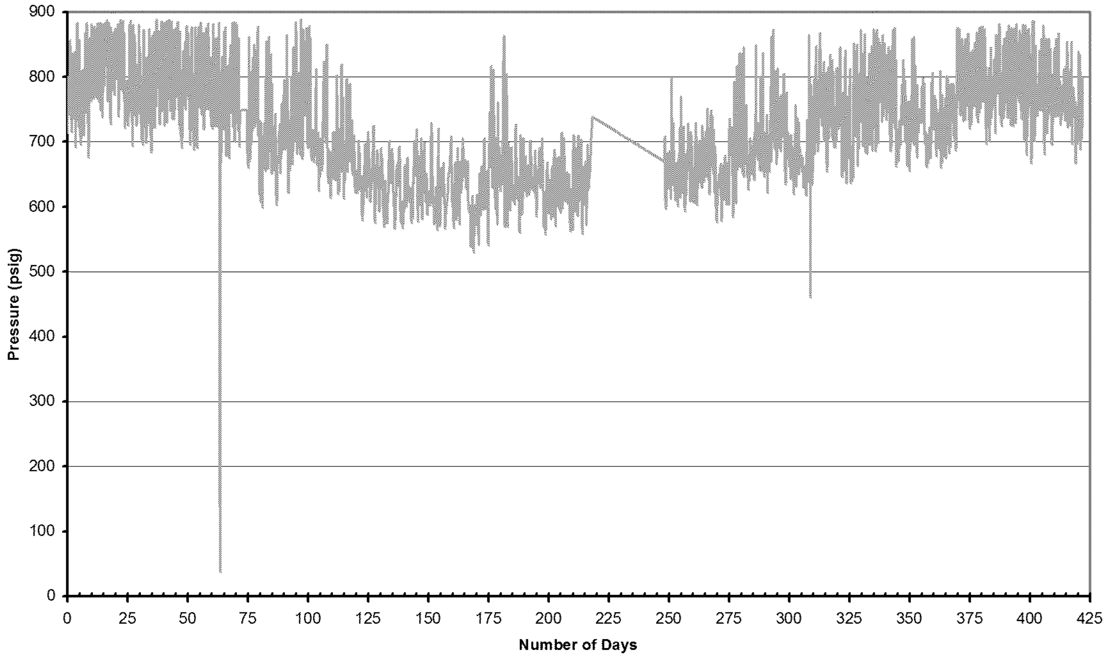

Figure 1. Pressure Levels in Gas Pipeline No. 1

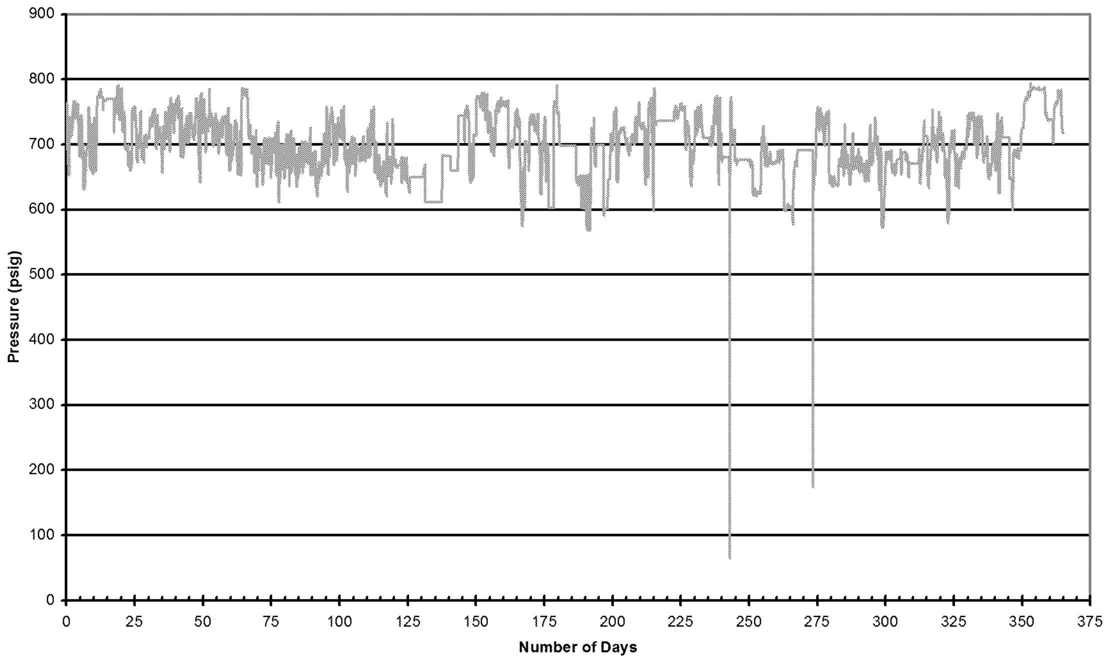

Figure 2. Pressure Levels in Gas Pipeline No. 2

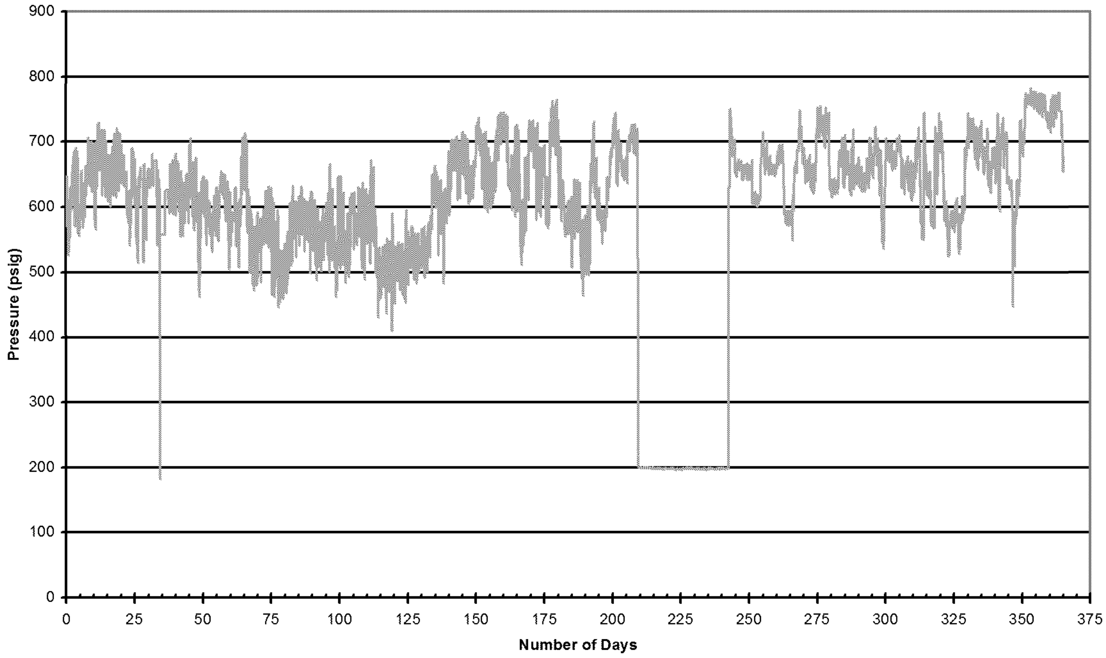

Figure 3. Pressure Levels in Gas Pipeline No. 3

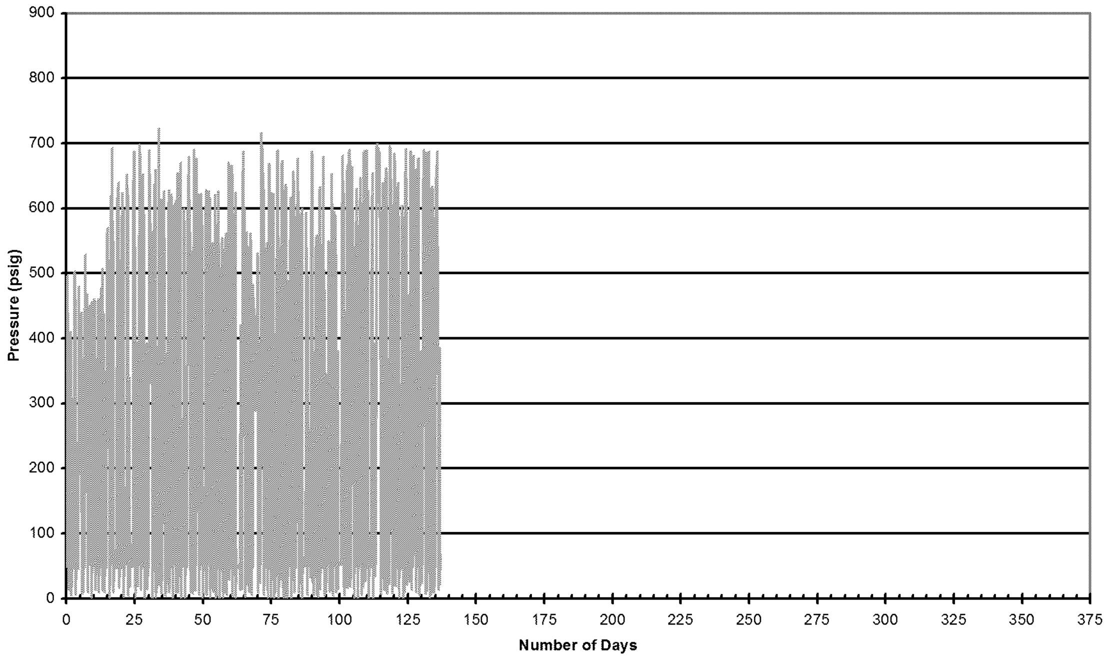

Figure 4. Pressure Levels in Liquid Pipeline

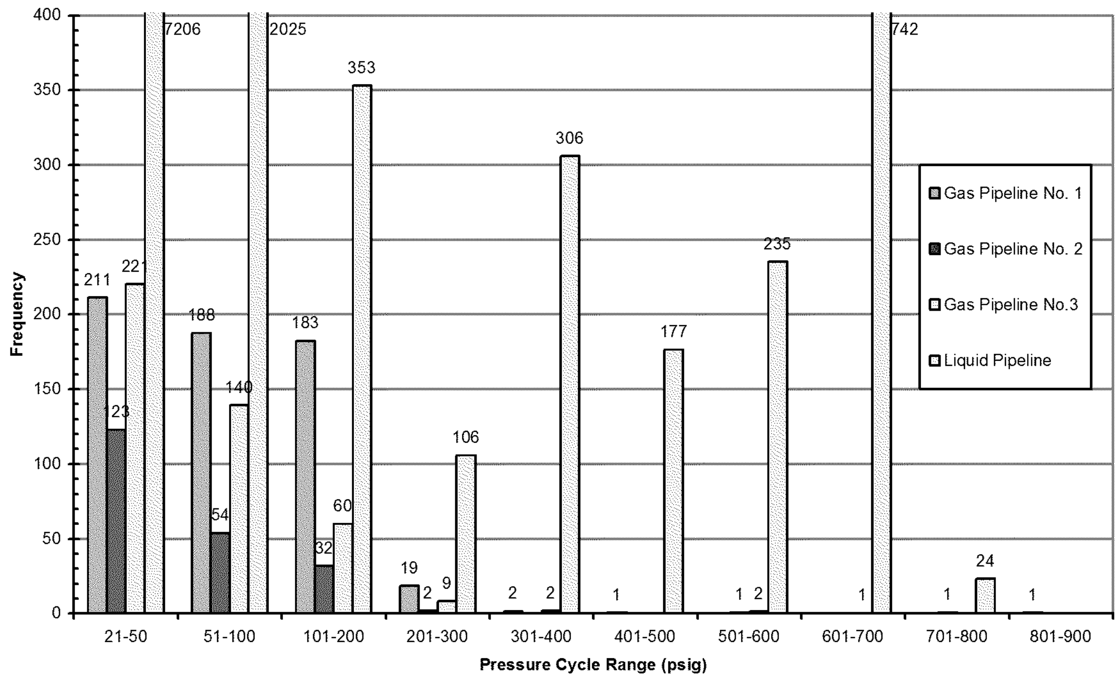

Figure 5. Rainflow-Counted Pressure Cycles

APPENDIX A

Benchmark Pressure Cycles

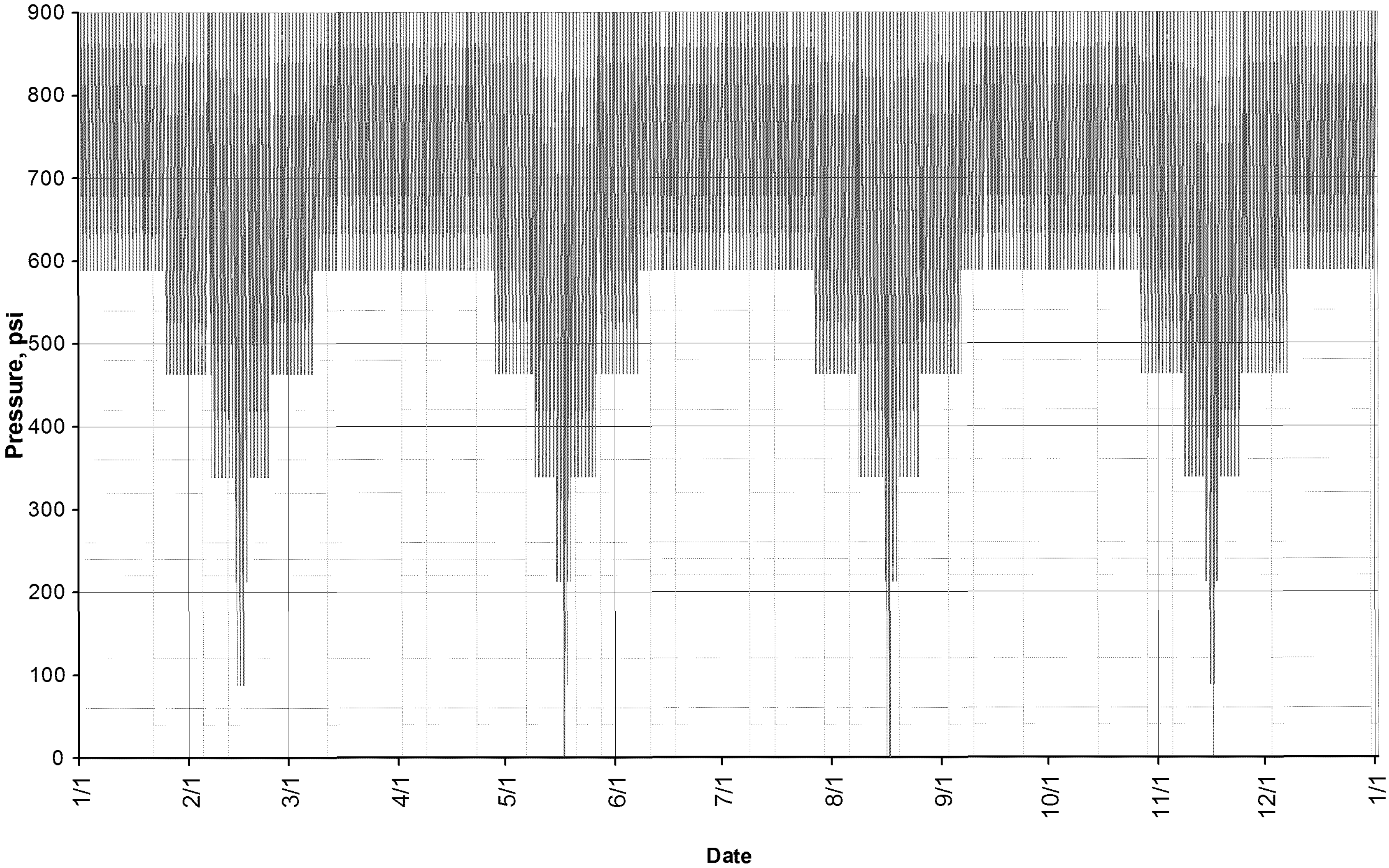

Figure A-1. Very Aggressive Benchmark Cycles

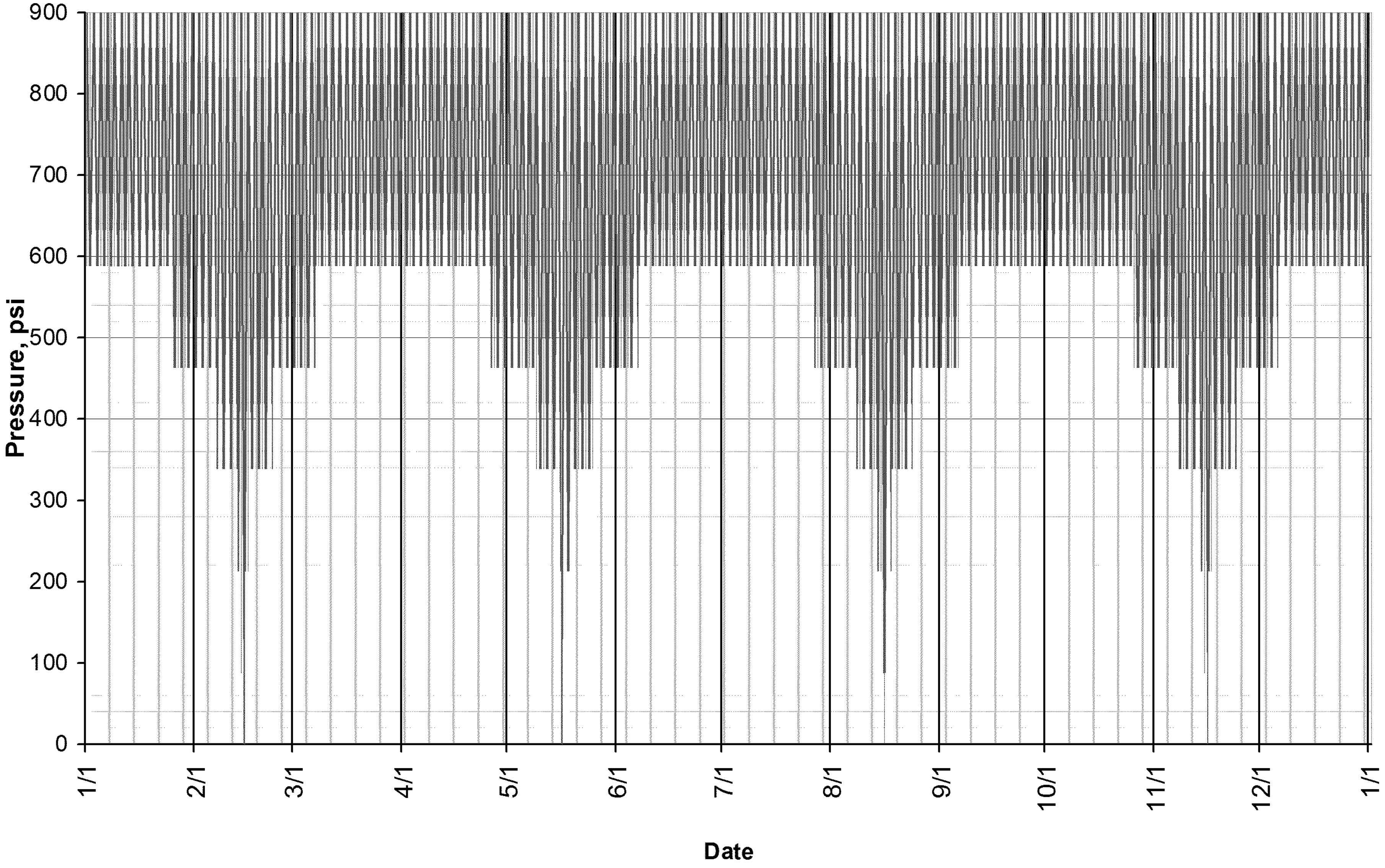

Figure A-2. Aggressive Benchmark Cycles

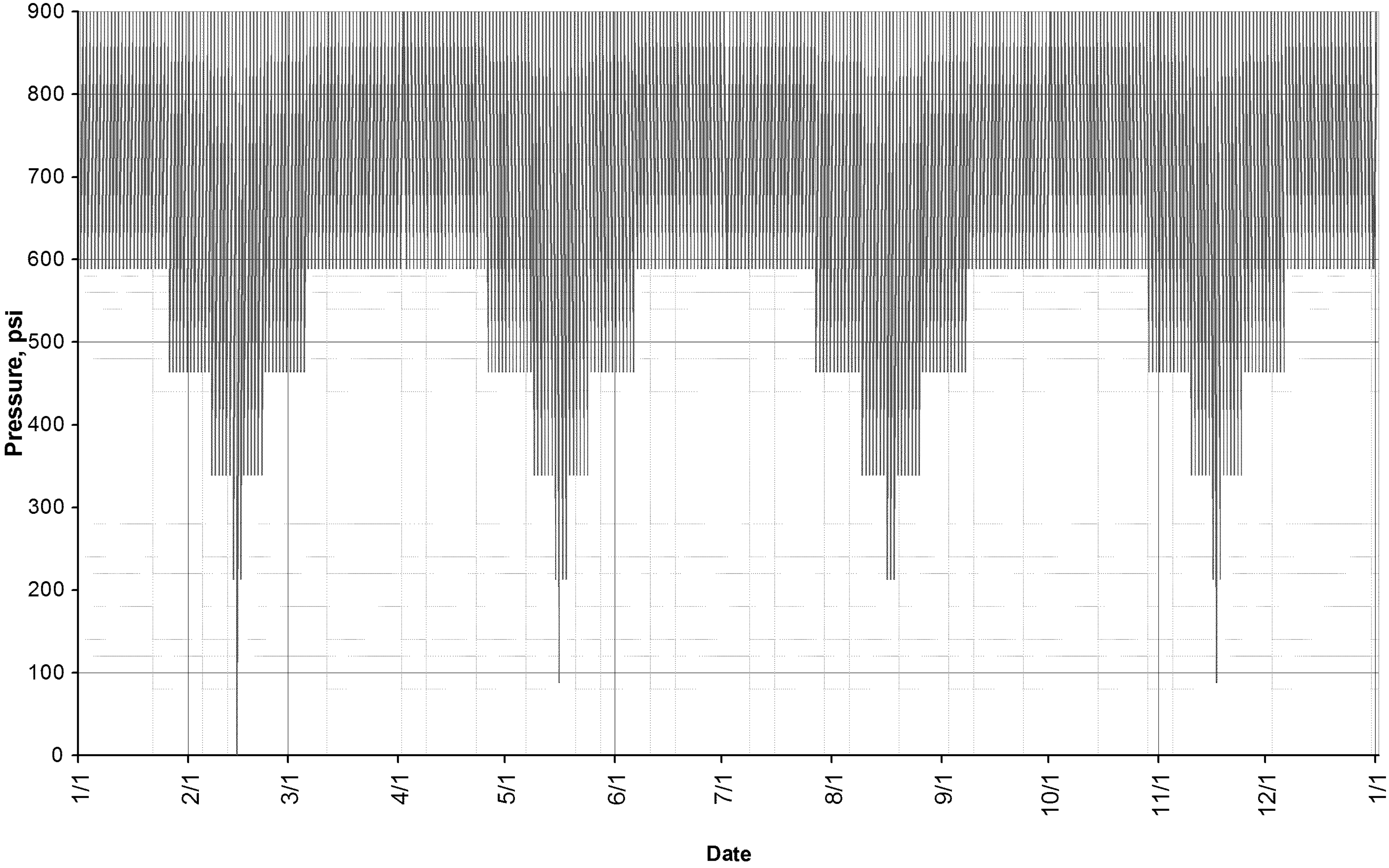

Figure A-3. Moderate Benchmark Cycles

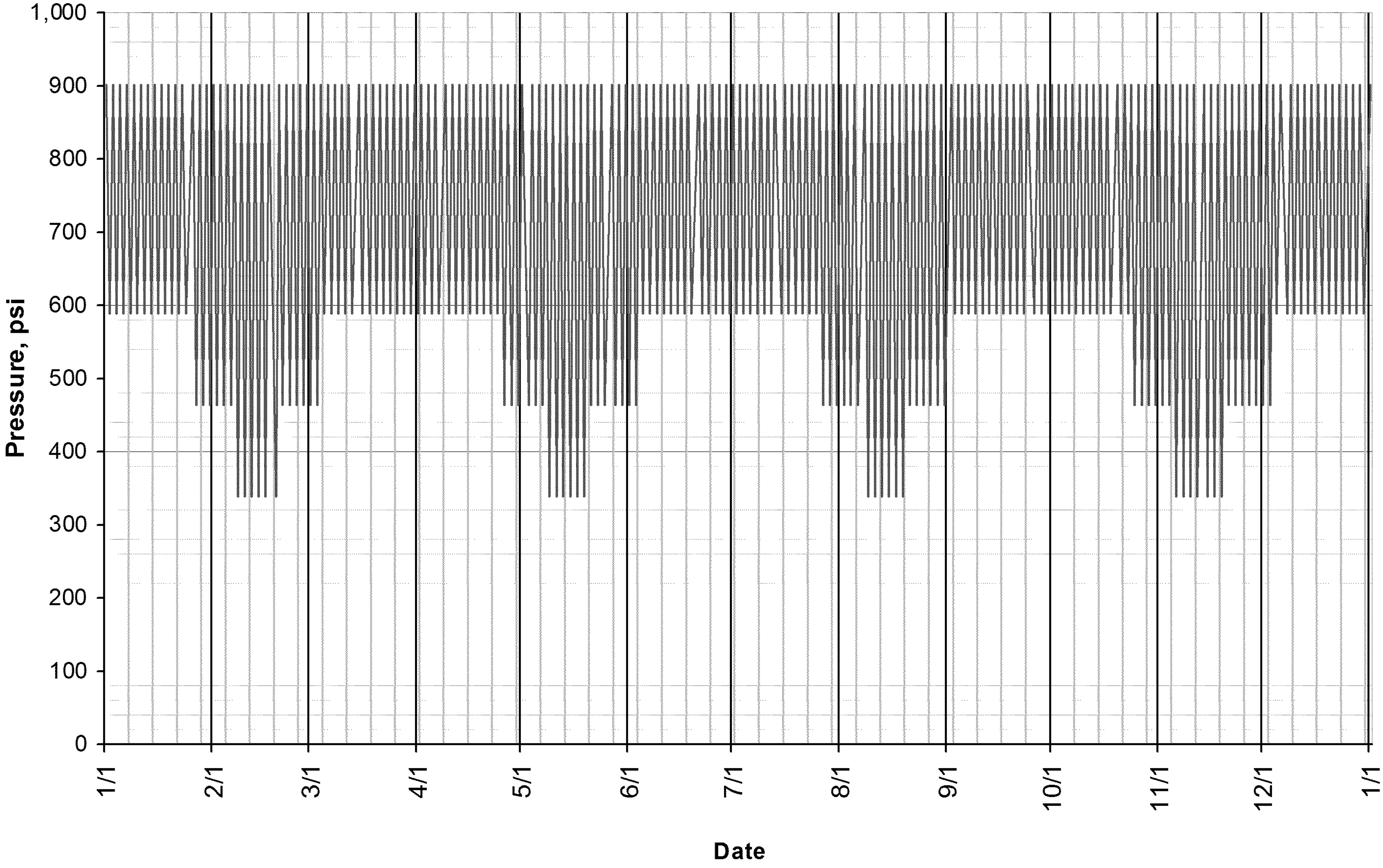

Figure A-4. Light Benchmark Cycles

ATTACHMENT 6

Kiefner & Associates, Inc., Letter from Michael

Rosenfeld to Jane Yura, September 10, 2011;

Provided as response to DR_CCSF_001-Q05Atch02.

Kiefner & Associates, Inc.

September 10, 2011

Ms. Jane Yura
Vice President, Gas Operations, Standards: Policies
Pacific Gas & Electric Company
77 Beale Street
San Francisco, CA 94105

Re: Hydrostatic pressure "spike" test

Dear Ms. Yura:

You have requested a clarification of the concept of the hydrostatic pressure "spike" test for natural gas pipelines. Specifically, you asked under what circumstances the spike test is appropriate.

A standard hydrostatic pressure strength or proof test is held at a more-or-less constant pressure level that is greater than the maximum allowable operating pressure (MAOP) by a minimum ratio that is specified by regulations or standards for the pipeline construction and operation. The minimum test pressure must be maintained for a specified period of time, usually 8 hours as specified by 49 CFR Part 192, Subpart J. During the test period, the pressure is usually allowed to vary within a range above the minimum test pressure to allow for the effects of thermal expansion of the test fluid. Decades of industry operating experience and scientific analysis has shown that the standard hydrostatic pressure test, without a pressure spike, is a reliable and proven technique for demonstrating the strength of the pipe and components installed in a natural gas pipeline and for establishing their MAOP.

The spike test involves subjecting the piping system to a maximum pressure level that is held for a short duration at the beginning of the test, followed by a longer-duration hold period at a reduced pressure. The pressure during the spike interval corresponds to a hoop stress in the pipe that may be near or above the specified minimum yield strength (SMYS) of the pipe. The purpose of the spike test is two-fold: the very high pressure interval will induce pipe failure where significant defects such as potential cracks are suspected to be present, while the subsequent pressure relaxation allows any surviving cracks to stabilize and avoid subcritical crack growth during the following 8-hour hold period to detect significant leaks. To be effective, the duration of the spike test interval only needs to be a few minutes but is often held for as long as 30 minutes. The subsequent pressure reduction must be at least 5% of the spike test pressure level in order to stop flaw extension at the highest test pressure. A reduction of 10% appears to prevent most flaw growth during the test, and most spike testing plans reduce the pressure 10% accordingly.

Current natural gas pipeline regulations in Part 192, Subpart J require that the minimum ratio of test pressure to operating pressure be held for a full 8 hours. A spike test is not required by Subpart J to establish the MAOP of the pipe. A spike test where the high level equals the minimum required test pressure and then the pressure is reduced for the hold period would not meet the requirements of Subpart J. In order to comply with present regulations the spike interval of a spike test must therefore be at a higher pressure than the minimum test level required by regulations by at least 5%, and more typically 10%.

The spike test was initially developed as a mitigation technique for stress-corrosion cracking (SCC). In that application, the spike pressure level is generally in the range of 105% to 110% of SMYS, while the hold for leaks is between 90% and 100% of SMYS. The spike test used to prove the integrity of some older vintage ERW seams that have exhibited a tendency to fail at levels above the mill test pressure is usually limited to around 90% to 95% SMYS (if a successful test at that level can be achieved) while the hold period to check for leaks is reduced 5% to 10% from that level. The final MAOP is established by the minimum required test pressure ratio with respect to the hold period in accordance with the regulations.

It is possible to consider three categories for the appropriateness of a spike test: (1) advisable, (2) unnecessary or discretionary, and (3) undesirable. These are described below.

1. Spike testing is beneficial and therefore recommended in certain specific circumstances, namely:
    a. Where crack-like defects such as SCC, selective corrosion of ERW seams, bond line defects in older vintage ERW seams, and seam fatigue cracks are expected to exist based on evidence from inspections or failures; or
    b. Where it is desired to increase the retest interval for time-dependent flaws; or
    c. Where documentation is unable to confirm the attributes of the pipe and also unable to confirm that a prior hydrostatic test has occurred.
2. Spike testing is unnecessary though not harmful, and is therefore discretionary, in the following situations:
    a. Where the purpose of the test is to demonstrate the strength of the pipe where crack-like defects are not expected to be present;
    b. Where the standard test margin is 1.4 or greater; or
    c. Where the pipe being tested is new.
3. Spike testing would be undesirable in certain specific circumstances, including:
    a. Where the spike pressure above the minimum required standard test level could damage pipe;
    b. Where the spike pressure level would exceed the recommended maximum test pressure levels of components such as flanges or valves; or
    c. Where the margin above the spike pressure level could be insufficient to prevent damage to the pipe due to a pressure increase caused by fluid thermal expansion effects during the test, which could be the case where the test encompasses a large elevation spread, the test section is very short, or the test temperatures are high.

The NTSB has recommended conducting a spike test followed by a standard hydrostatic strength test specifically in high-consequence area pipeline segments where records are unable to confirm the pipe attributes and also unable to confirm that a prior hydrostatic pressure test took place, as listed in (1)(c) above. The NTSB's recommendation to conduct spike testing is reasonable within the suggested scope, but it cannot be generalized to all testing situations. A spike test should be considered unnecessary in many conventional testing situations, such as those listed in category (2) above. Note that this includes situations where the standard test margin is 1.4 or greater, as listed in (2)(b) above. The rationale for (2)(b) is that pressure reversals as large as 30% of the test pressure have been shown to be statistically exceedingly improbable. Therefore, a reduction in pressure for the leak test from the high pressure is unnecessary, so whether the test is performed in a spike format is irrelevant. Finally, there are situations listed above in category (3) where a spike test could be harmful and is therefore not recommended.

With respect to the recently completed hydrostatic tests at Topock Compressor Station, it is noted that the operating stress levels range from 14% to 47% of SMYS depending on pipe size, the pressure test ratio is at least 1.5, and the pipe installed at Topock is of known type. What is important to establishing the MAOP in this case is the ratio of test pressure to operating pressure. Whether the test is conducted in the spike test format is unimportant to establishing the MAOP of the pipe and the absence of a spike test level in this case does not cause the test to be deficient. Furthermore, the facility contains components having recommended maximum test pressure limits. A spike test that encroaches on those limits could cause damage and is not recommended.

If you have further questions on this matter, please feel free to contact me.

Sincerely,

Michael J. Rosenfeld, PE
President

cc:
Michelle Cooke, CPUC
Julie Halligan, CPUC
Sunil Shori, CPUC

ATTACHMENT 7

Hughes Report to PG&E Co., "Fire Hazard Area Evaluation, Radius of Influence for Jet Fires," 40 Rev 3, March 24, 2011, p. 7.

CONFIDENTIAL DUE TO NAMES

ATTACHMENT 8

Gas Research Institute, GRI-95/0101, "Final Report – Remote and Automatic Main Line Valve Technology Assessment," July 1995, p. 74.

Remote and Automatic Main Line Valve Technology Assessment

Final Report
GRI Report No. GRI-95/0101

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July 1995

TABLE II. CALCULATED BLOWDOWN TIMES (IN MINUTES) FOR A FULL LINE BREAK AT THE END OF A 1000 PSI PIPELINE, SHOWING THE EFFECT OF LINE LENGTH AND DIAMETERS

Nominal Line Size	Pipe I.D.	1 mile	2 miles	5 miles	10 miles	15 miles
42	41"	0.78	2.05	7.68	21.22	38.69
36	35"	0.83	2.19	8.23	22.85	41.69
30	29"	0.88	2.35	8.96	24.96	45.60
24	23.25"	0.95	2.58	9.90	27.71	50.70
20	19.25"	1.02	2.79	10.80	30.32	55.51
16	15.25"	1.11	3.09	12.03	33.89	62.13
12	12.00"	1.23	3.43	15.37	38.02	69.79

ATTACHMENT 9

AGA White Paper, "Automatic Shut-off Valves (ASV) And Remote Control Valves (RCV) On Natural Gas Transmission Pipelines," March 25, 2011, p. 3.

AGA White Paper
Automatic Shut-off Valves (ASV)
And
Remote Control Valves (RCV)
On Natural Gas Transmission Pipelines

March 25, 2011
AGA Distribution & Transmission Engineering Committee

Executive Summary

This AGA white paper was developed to provide information regarding the relative benefits, challenges, issues, feasibility, costs and performance expectations associated with the installation of Automatic Shut-off Valves (ASVs) or Remote Control Valves (RCVs) on existing and new natural gas transmission pipelines. This white paper provides natural gas pipeline operators, federal and state regulators, public interest groups and the general public with information and guidance on considerations for the use of such valves in existing and new natural gas transmission pipeline systems within populated areas.

Federal pipeline safety regulations require operators to install in-line sectionalizing valves ("block valves") on natural gas transmission pipelines at prescribed intervals in order to completely shut off the flow of gas for both routine maintenance activities and emergency response. One of the existing provisions of the Transmission Integrity Management Program (TIMP) rule is for operators to evaluate if the use of ASVs or RCVs would be an efficient means to add protection to High Consequence Areas (HCAs) in the event of a natural gas release.

An Automatic Shut-Off Valve (ASV) is a valve that has electric or gas powered actuators to operate the valve automatically based on data sent to the actuator from pipeline sensors. The sensors will send a signal to close the valve based on predetermined criteria, generally based on pipeline operating pressure or flow rate. The ASV does not allow or require human evaluation or interpretation of information surrounding an event to determine if the event is a legitimate incident, and will close automatically based on the established criteria.

A Remote Control Valve (RCV) is a valve equipped with electric or gas powered actuators to operate (open or close) the valve based on an order (signal) from a remote location, such as a gas control room. The RCV requires operating personnel in the remote location to review and evaluate data in their system and make a determination whether a problem does, or does not, exist based on available information, such as operating pressure and flow data transmitted from the pipeline, or communications from the public, emergency responders or company personnel on site. Based on available information, if the operator determines that there is a problem that would require a valve closure, they may execute a command to close the valve remotely. The RCV introduces human intervention, decision making, evaluation and the possibility of human error into the process.

There are potential benefits associated with the use of ASVs and RCVs. The primary benefit is that ASVs and RCVs normally close more rapidly than a manually operated valve that requires operating personnel to travel to the valve location.

Operators have installed ASVs on pipeline segments that have not experienced wide pressure fluctuations, and are not expected to experience wide pressure fluctuations in the future, and where the risk analysis indicates the ASV will provide added protection to an HCA or in certain remote locations.

An RCV allows a control room operator to execute a signal to close a line valve when an incident occurs. The RCV allows a line valve to be operated sooner than a manually operated valve, once a decision has been made by personnel monitoring the remote pipeline data that an emergency condition exists. The potential time savings of an RCV is based on a number of variables, including the physical location of the valve relative to available operating personnel and the amount of time before the controller determines that an emergency condition exists and acts to close the valve. Whenever possible, it is prudent for the gas controller to confirm actual field conditions prior to executing an order to close a transmission line valve. Operators have installed RCVs in locations where the risk analysis indicates the RCV will provide added protection to an HCA or in certain remote locations.

Operators should recognize that the presence of an ASV or RCV on a transmission pipeline will not prevent an incident from occurring and may not lessen any related injury to persons or damage to property. Studies on the potential benefits of ASVs and RCVs for natural gas transmission pipelines have concluded that the vast majority of injuries, fatalities and property damage occur within the first few minutes of a pipeline failure. For example, the July 2010 study *"Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing"* conducted by Robert J. Eiber Consultant Inc and Kiefner and Associates, concluded that "injuries and fatalities generally occur within the first 30 seconds following gas release" and "closure of a block valve does not immediately reduce the release of natural gas from the pipeline". The study's review of 13 NTSB gas transmission pipeline incidents indicated that the consequences of the incidents examined would not have changed if the valves closed immediately after the release of gas An ASV or RCV will not react quickly enough to prevent serious consequences from happening following pipeline failure. The primary benefit of an ASV or RCV is the ability to control the amount of natural gas released after the incident has occurred.

Operators should also recognize that the conversion of a manual valve to an ASV or RCV in an urban environment will be challenging and may not be possible. The vast majority of existing transmission lines in urban areas and those integrated within distribution systems were not designed or constructed to accommodate the retrofit installation of ASVs or RCVs. For transmission lines in urban areas or contained within distribution systems, the lack of underground space immediately adjacent to the existing valve, which is necessary to install a vault to contain the ASV or RCV and the valve actuating equipment, make the conversion of a manual valve to an ASV or RCV extremely difficult to virtually impossible.

Where physical space is available, the cost of converting an existing manual valve in an HCA to an ASV or RCV will range from approximately $100,000 to $1,000,000. The cost to install a new ASV or RCV in an existing transmission pipeline will range from approximately $200,000 to $1,500,000 (costs may be more in dense urban areas). The cost to install a new ASV or RCV on a new transmission pipeline or fully replaced transmission pipelines will range from approximately $100,000 to $1,000,000. The range of costs is significantly affected by a multitude of factors such as pipe size, location, operating pressure, proximity to adjacent utilities, etc. The costs to install an ASV or RCV in a rural location is typically lower than the costs referenced in this white paper due to less congestion of other utilities in the underground rights-of-way and the possibility of installing the ASV or RCV in above-ground locations that do not require the installation of a vault.

While ASVs and RCVs may provide faster closure of a valve than a manually operated valve, they also introduce the possibility of a false valve closure with unintended consequences. For example, ASVs could inadvertently close due to routine events such as a decrease in pipeline pressure due to peak cold or hot weather flow rates. An RCV could be closed without confirmed information or observation of the appropriate pipeline segment, especially where there are multiple pipelines in close proximity or valves close together. The resulting impact could be the loss of service to thousands of customers for multiple days or weeks, including sensitive customers such as hospitals, schools, chemical plants and power plants.

Table of Contents

I. Purpose and Scope

The intent of this white paper is to provide information and guidance for operators on considerations for the use of Automatic Shut-off Valves (ASVs) and Remote Control Valves (RCVs) in existing and new natural gas transmission pipeline systems within populated areas. Please note that this paper does not serve as a technical standard and does not provide instruction on state or federal regulatory compliance. Each operator should develop a policy with respect to the installation of ASVs and/or RCVs that is appropriate for its system.

There are fundamental differences in the use of in-line valves in natural gas transmission pipelines and those used in hazardous liquid pipelines. This document does not attempt to discuss the benefits or problems associated with ASV or RCV applications in liquid pipelines.

II. General Definitions

Actuator: A mechanism that operates (opens or closes) a valve by the use of electric, pneumatic or hydraulic power.

Automatic Shut-Off Valve (ASV): A valve that has electric or gas powered actuators to operate the valve automatically based on data sent to the actuator from pipeline sensors. The sensors will send a signal to close the valve based on predetermined criteria, generally based on pipeline operating pressure or flow rate. The ASV does not allow or require human evaluation or interpretation of information surrounding an event to determine if the event is a legitimate incident, and will close automatically based on the established criteria.

Class Location: Pipeline locations as classified by criteria found in 49 CFR 192.5. A given pipeline segment's classification is based on the population density along its route as characterized by the number and type of buildings as well as any places of public assembly found in a defined area surrounding the segment. See Appendix A for details.

Control Room: An operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling entire or multiple sections of pipeline systems.

Gas Controller: A qualified individual whose function is to remotely monitor and control the safety-related functions of entire or multiple sections of pipeline system via a SCADA system from a pipeline operator's Control Room, and who has operational authority and accountability for the remote operational functions of pipeline systems as defined by the operator.

High Consequence Area (HCA): Is defined in 49 CFR §192.903. Generally, for the purposes of this white paper, a HCA is an area that is defined by the population density or calculated by using a formula that accounts for product transported, the pipeline's diameter and the pipeline's operating pressure. This area lies along either side of a pipeline in areas where a pipeline failure could affect a large number people causing injuries, fatalities and/or extensive property damage.

In-Line Inspection (ILI) Tools: Tools used to inspect a pipeline from the interior of the pipe. May also be referred to as intelligent or smart pigging tools.

MAOP: The Maximum Allowable Operating Pressure for a specific section of pipeline.

Remote Control Valve (RCV): A valve equipped with electric or gas powered actuators to operate (open or close) the valve based on an order (signal) from a remote location, such as a gas control room. The RCV requires operating personnel in the remote location to review and evaluate data in their system and make a determination whether a problem does, or does not, exist based on available information, such as operating pressure and flow data transmitted from the pipeline, or communications from the public, emergency responders or company personnel on site. Based on available information, if the operator determines that there is a problem that would require a valve closure, they may execute a command to close the valve remotely. The RCV introduces human intervention, decision making, evaluation and the possibility of human error into the process.

Remote Shut-Off Valve (RSV): A Remote Control Valve, as used in this white paper.

Supervisory Control and Data Acquisition System (SCADA): A computer-based system or systems used by Gas Controllers in the Control Room that collects and displays information about pipeline systems and has the ability to send commands back to the pipeline systems.

III. Shut-Off Valves on Transmission Lines - Background

Shut-off valves, known as sectionalizing block valves or "block valves," are installed in transmission lines primarily to isolate pipeline segments to facilitate future maintenance, operations or construction work. In the event of a pipeline leak, rupture or other component failure unintentionally releasing natural gas, block valves are closed to limit the amount of product lost.

a. Regulatory Requirements

The federal pipeline safety regulations (49 CFR 192.179) require all transmission lines to have sectionalizing block valves installed at specific intervals, based on population density, to allow the timely interruption of gas flow in the event of an emergency. Natural gas sectionalizing valves are required at a reduced spacing between valves as population density increases as follows:

- Each point on a pipeline in a Class 1 location must be within 10 miles of a valve
- Each point on a pipeline in a Class 2 location must be within 7 ½ miles of a valve
- Each point on a pipeline in a Class 3 location must be within 4 miles of a valve
- Each point on a pipeline in a Class 4 location must be within 2 ½ miles of a valve

In addition to minimum spacing requirements, 49 CFR 192.179 requires sectionalizing block valves to be readily accessible and protected from tampering and damage, as well as properly supported to prevent settling of the valve or movement of attached pipe.

49 CFR 192.935 requires the pipeline operator to take additional measures to prevent or mitigate the consequences of pipeline failure in a High Consequence Area (HCA). The use of ASVs/RCVs is addressed in 49 CFR 192.935(c). Specifically:

> *(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.*

b. Current Industry Practice

Operators generally use manually operated valves to comply with the requirements of 49 CFR 192.179. The specific types of block valve configurations include plug valves, reduced-port and full-port ball valves and gate valves.

A "gate valve" contains a rectangular or circular plate that is lowered into the pipe to stop the flow of gas when closed. A "plug valve" contains a tapered plug with a rectangular opening to stop the flow of gas when closed. The rectangular opening is relatively small compared to the inside cross-section of the pipe, restricting the flow of gas significantly and presenting an obstacle to the passage of in-line inspection (ILI) tools. A "reduced-port ball valve" contains a spherical ball to stop the flow of gas when closed. The reduced-port opening is larger than the opening in a plug valve, but still smaller than the cross-section of the pipe, restricting the flow of gas somewhat and presenting a potential obstacle to the passage of ILI tools. A "full-port ball valve" is similar to a reduced-port ball valve except that the opening in the spherical ball is approximately the same size as the cross-section of the pipe, presenting little restriction to the flow of natural gas or the passage of ILI tools. Plug valves and gate valves were generally installed in older transmission lines, whereas the majority of block valves installed in newer transmission lines are reduced-port or full-port ball valves. Since 1994, federal pipeline safety regulations required all new transmission pipeline installations to be capable of passing an ILI tool. For that reason, operators have generally used full-port ball valves after that time.

Operators may choose to install block valves at additional locations beyond the minimum requirements of 49 CFR 192.179 based on a multitude of factors such as pipeline size, operating pressure, location, response time, branch connections, and physical factors such as river, railroad or bridge crossings. Block valves may also be spaced more closely in anticipation of future construction, operations or maintenance work.

Over the years, operators have considered the use of ASVs/RCVs at locations where the unique operating characteristics of these valves add operational flexibility and makes safe operation of the system more efficient. Although not extensively used in natural gas transmission infrastructure that is associated closely with distribution systems, a number of such valves have been installed to control the flow of gas at city gates and other major measurement and regulation (M&R) stations, large end users, storage facilities, system interconnects and as shut-off valves at remote locations.

c. Depressurization Times

The amount of time for a section of transmission pipeline to "blow down" (depressurize to 0 psig) if it is isolated by closing block valves (manually operated, automatic shut-off or remote control valve) is based on a number of variables, including: diameter of pipeline, distance between isolation valves, internal pipeline restrictions, operating pressure of the line at the time of valve closure and physical dimensions of the opening at the point of pipeline failure. Depending on these physical parameters, a pipeline may take a considerable amount of time to reach 0 psig after the valves are closed (ranging from tens of minutes to several hours).

IV. Automatic Shut-Off Valves (ASVs)

a. Benefits

An ASV will automatically close when the pressure sensors near the valve detect a pressure drop that meets predetermined operating criteria. An ASV normally closes more rapidly than a manually operated valve that requires operating personnel to travel to the valve location. Operators have installed ASVs on pipeline segments that have not experienced wide pressure fluctuations, and are not expected to experience wide pressure fluctuations in the future, where the risk analysis indicates the ASV may provide added protection to a HCA or in certain remote locations.

b. Challenges and Issues

An ASV will automatically close if the pressure sensors near the valve detect a pressure drop that is representative of the large gas loss that would be associated with a pipeline rupture. However, since the valve will operate automatically without human evaluation or interpretation of system operating data, there is a possibility of an unintended valve closure and related consequences. For example, during winter peak load operations, it is possible for a transmission line to experience significantly increased flow rates and reduced system operating pressures that may have operating similarities to a transmission line failure. Since the valve is programmed to close under these types of conditions, it may incorrectly sense that there is a transmission line failure and close the valve. The false closure of a transmission block valve under peak load conditions may subject the operator to widespread customer outages, customer product losses and safety impacts. Reintroduction of gas into a system that has experienced loss of supply must be performed carefully to prevent serious safety implications.

Contingencies, such as temporary reconfiguration of pipeline flow and pressure, which are common on local distribution company (LDC) transmission systems during routine construction, maintenance or cold weather operations, can be complicated by the presence of ASVs. During these types of situations, the pressure in the pipeline may be reduced to unusually low levels and the ASV may close, incorrectly sensing that a gas release has occurred. In addition, it is possible for an ASV to malfunction and partially or completely close, presenting a serious flow restriction that may be difficult to identify and correct. It is also possible for a serious incident to occur without initiating an ASV closure. Finally, ASVs must be kept secure to prevent vandalism or sabotage.

V. Remote Control Valves (RCVs)

a. Benefits

An RCV allows a control room operator to execute a signal to close a line valve when an incident occurs. The RCV allows a line valve to be operated sooner than a manually operated valve, once a decision has been made by personnel monitoring the remote pipeline data that an emergency condition exists. Whenever possible, it is prudent for the gas controller to confirm actual field conditions prior to executing an order to close a transmission line valve.

The potential time savings of an RCV is based on a number of variables, including but not limited to the physical location of the valve relative to available operating personnel and the amount of time before the controller determines that an emergency condition exists and acts to close the valve.

Operators have installed RCVs in locations where the risk analysis indicates the RCV may provide added protection to an HCA or in certain remote locations.

Figure 1 shows an example of a typical RCV valve installation contained in an underground vault.

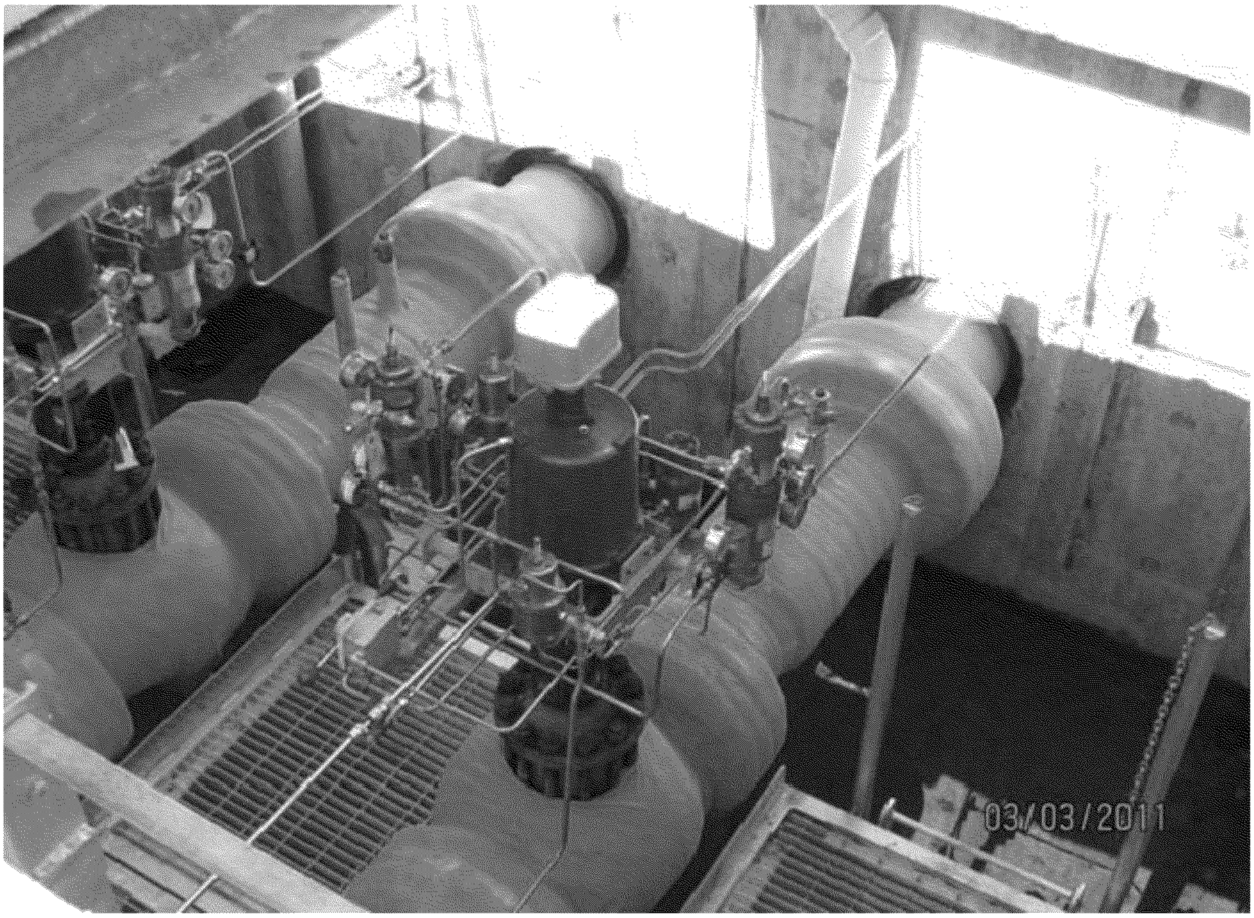

Figure 1

b. Challenges and Issues

The installation of an RCV does not ensure immediate valve closure during an incident. The RCV requires personnel (usually gas controllers) responsible for monitoring system operating conditions to evaluate system conditions based on pressure or flow data transmitted from the pipeline in remote locations. Based on available information, the gas controller must evaluate whether an apparent anomaly in operating conditions constitutes an incident or emergency, requiring an immediate valve closure, or whether the unusual condition is based on a routine event, such as a high flow condition due to peak cold weather system flow rates, the start-up of a major industrial customer, or simply instrumentation malfunction.

The RCV presents the possibility that the control room operator could execute a signal to close a line valve, based on incomplete information, before a field situation has been appropriately evaluated. Unnecessary valve closure could compromise public safety and cause serious consequences, such as product loss and widespread customer outages, including outages to sensitive customers such as hospitals, schools, chemical plants and power plants.

In addition, the equipment necessary to monitor and actuate RCVs may be susceptible to physical and cyber security issues and sabotage such as intrusion into computer systems, communications links, breaching of physical security at valve locations and vandalism. There is also the possibility of routine equipment failure. Any equipment failure could have severe adverse consequences to the public.

VI. Converting Existing Manual Valves to ASVs/RCVs

ASVs and RCVs are significantly more complicated to install than manually operated sectionalizing valves. A manually operated valve is generally welded into the pipeline during the initial construction process. The valve assembly, which occupies little physical space, is typically buried along with the pipe. The operation of such a buried valve is typically performed by way of a valve access box at the surface.

There are several challenges that must be overcome when converting a manually operated valve to an ASV or RCV. An ASV or RCV requires additional equipment such as actuators, pressure and/or flow sensing devices and associated piping, power and telecommunications equipment. This equipment requires a relatively large space either above ground or below ground. In a HCA, such as a subdivision or downtown location, this equipment must be installed in an underground vault large enough to house the valve, equipment and a person conducting maintenance or repair around the valve or equipment. These vaults are approximately 10'x16'x10'and may be larger depending on the size of the valve. Since pipelines in HCAs are generally in city streets, the underground infrastructure around the pipeline is typically congested with water, sewer lines, telecommunications, power, traffic signal lines and other underground infrastructure. The challenge is finding enough underground real estate to house the ASV or RCV and the equipment necessary to operate the valve. In addition, the vault must be designed and constructed to structurally support large vehicular loads.

Due to the limited availability of underground real estate in urban and suburban areas, it is possible that an existing sectionalizing valve may have to be relocated to allow the installation of ASV or RCV capabilities. The valve relocation may result in valve spacing exceeding the maximum spacing allowed by federal code, requiring the installation of additional sectionalizing valves.

Other factors that must be considered when converting from an existing manual valve to an ASV or RCV include:

- Most existing buried valves are not deep enough to accommodate installation of an actuator or other ASV or RCV equipment. This requires off-setting of the pipeline to provide sufficient depth for the valve and related equipment
- Many existing valves are not compatible with available actuators
- Above ground space is generally not available for ASVs or RCVs in HCAs
- Areas with a high water table or flooding conditions may create reliability problems for electronic or pneumatic actuators and related instrumentation installed in vaults below grade
- Power and telecommunication access may need to be installed to the area where the ASV or RCV will be located

The cost to convert an existing valve to an ASV or RCV will vary due to the technical challenges referenced above. The most significant cost factors are the pipeline (valve) size, operating pressure, and site specific conditions. Generally, the cost to retro-fit an existing manually operated transmission line valve with ASV or RCV capabilities is estimated to be between $100,000 and $1,000,000 with higher costs in dense urban areas, especially if offsets are required.

VII. Adding ASVs/RCVs to an Existing Transmission Line

As noted in section VI above, ASVs and RCVs are more complicated and challenging to install and operate than manually operated sectionalizing valves. The installation of a new block valve, equipped with either ASV or RCV functionalities, on an existing pipeline, presents the challenges and obstacles identified in section VI above and some additional challenges.

There are a number of considerations that must be taken into account when installing an ASV or RCV on an existing pressurized transmission line, especially transmission lines that are integrated within distribution systems. Transmission pipelines that are integrated with distribution systems typically do not have parallel transmission lines or integrated, back-fed systems. In order to install the new valve, operators must identify a location that has sufficient underground vault space available to accommodate the new valve, actuators, instrumentation and related appurtenances. The operator must then install line stopper (flow stopping) equipment on the live pipeline, upstream and downstream of the new valve location, allowing the line to be taken out of service while the new valve is installed. In order to maintain the continuity of safe and reliable service to customers served by the transmission line, a temporary "bypass pipeline" must be installed around the valve installation site. Operators must consider downstream system demands when scheduling the installation of ASVs or RCVs. Due to system reliability considerations, there may be limited times during the year that transmission lines serving critical customers can be shutdown. NOTE: Working on a live natural gas transmission pipeline under pressure presents some of the most safety sensitive work performed by natural gas operating companies. Operators need to strictly follow company safety practices when conducting such work.

The cost to install an ASV or RCV on an existing transmission line will vary due to the technical challenges referenced above. The most significant cost factors are the pipeline (valve) size, operating pressure, and site specific conditions. Generally, the cost to install a new transmission line sectionalizing valve, equipped with ASV or RCV capabilities, in an existing transmission line is estimated to be between $200,000 and $1,500,000 with higher costs in dense urban areas.

VIII. Installing ASVs/RCVs on New Transmission Lines

The installation of block valves equipped with ASV or RCV capabilities on a newly constructed transmission pipeline presents significant challenges and additional costs compared to the installation of typical manually operated valves. The installation of a new ASV/RCV-equipped valve on a new line requires the acquisition of a large volume of scarce real estate in a congested right-of-way to accommodate the traffic bearing vault, valve, actuators and related equipment identified in sections VI and VII above. In addition, many of the challenges to ASV/RCV installation discussed in sections VI and VII are also applicable to the installation of new ASV/RCV valves on new transmission lines, including the design and construction of large traffic bearing vaults, vault flooding and associated reliability issues, availability of power and/or telecommunication equipment.

However, if an operator elects to install sectionalizing valves with ASV or RCV capabilities on a new transmission pipeline, the most effective timing is to design and construct the pipeline with the installation of these valves in the original project scope. This foresight allows the operator to identify valve spacing, valve location, pipeline alignment and other design parameters to accommodate the significant additional demands of an ASV/RCV installation in an HCA application.

Based on the technical challenges referenced above, and considerable variability based on pipeline (valve) size, operating pressure, and site specific conditions, the cost to install a new transmission line block valve, equipped with ASV or RCV capabilities, in a new transmission line at the time of pipeline construction is estimated to range from approximately $100,000 to $1,000,000; costs could be significantly higher in dense urban areas.

IX. ASV/RCV Performance Expectations During Pipeline Incidents

Several studies have been conducted on the potential benefits of ASVs and RCVs. The results were summarized in a report by the Department of Transportation (DOT), Research and Special Programs Administration (RSPA) in September 1999, titled *"Remotely Controlled Valves on Interstate Natural Gas Pipelines"*, and updated in a report by Robert J. Eiber Consultant Inc. and Kiefner and Associates in July 2010, titled *"Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing."*

Based on these reports and underlying studies, the vast majority of injuries, fatalities, and property damage associated with a catastrophic pipeline incident occur within the first few minutes of the event, well before activation of ASVs or RCVs are possible. The 2010 study's review of 13 NTSB gas transmission pipeline incidents indicated that the consequences of the incidents examined would not have changed if the valves closed immediately after the release of gas.

The primary benefit of an ASV or RCV is the ability to control the amount of natural gas released after the incident has occurred. An ASV or RCV will normally close more rapidly than a manually operated valve that requires operating personnel to travel to the valve location. An ASV or a RCV will not close immediately after a pipeline incident. In the case of an ASV, the amount of time before the valve closes is dependent on a number of factors, including the initial operating pressure of the pipeline, distance from the pipe rupture to the ASV, physical characteristics (size) of the pipeline failure, set point of the actuator to initiate valve closure, and amount of time it takes the valve to actually close after actuation.

In the case of a RCV, the time to closure will be impacted by similar factors, including the initial operating pressure of the pipeline, distance from the pipe rupture to remote pressure sensing equipment, physical characteristics (size) of the pipeline failure, and the amount of time that it takes the pipeline to de-pressurize to an alarm level, gas controller to evaluate the situation and recognize that a pipeline failure may have occurred, controller to execute an RCV closure, and valve to close after the order is issued.

The decision to execute an RCV closure should not be taken lightly due to the high potential for adverse consequences to the public downstream of the closure. The evaluation process may include, but not be limited to:

- Reviewing the alarm data and looking for collaborating data.
- Performing diagnostics.
- Performing a system impact study downstream of the valve closure.
- Dispatching personnel to the scene to verify situation and data.

After the ASVs or RCVs are closed to isolate a pipeline incident, it will take additional time to depressurize the pipeline to 0 psig. This time will depend on the physical parameters of the pipeline and the pipeline failure.

X. Appendix A

Class location factor is defined by 49 CFR, § 192.5 as follows:

a. This section classifies pipeline locations for purposes of this part. The following criteria apply to classification under this section.

   (1) A "class location unit" is an on-shore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

   (2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

b. Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

   (1) A Class 1 location is:

      i. An offshore area; or

      ii. Any class location unit that has 10 or fewer buildings intended for human occupancy.

   (2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

   (3) A Class 3 location is:

      i. Any class location unit that has 46 or more buildings intended for human occupancy; or

      ii. An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

   (4) A Class 4 location is any class location unit where building with four or more stories above ground are prevalent.

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ATTACHMENT 10

Mark J. Stephens, C-FER Technologies, topical report prepared for Gas Research Institute, "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines," GRI-00/0189, October, 2000.

GRI-00/0189

A MODEL FOR SIZING HIGH CONSEQUENCE AREAS ASSOCIATED WITH NATURAL GAS PIPELINES

TOPICAL REPORT

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C-FER Report 99068

Prepared for:

GAS RESEARCH INSTITUTE
Contract No. 8174

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October 2000

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13. ABSTRACT (*Maximum 200 words)*

This report developed a simple and defendable approach to sizing the ground area potentially affected by a worst-case ignited rupture of a high-pressure natural gas pipeline. Based on this model, a simple equation has been developed that relates the diameter and operating pressure of a pipeline to the size of the area likely to experience high consequences in the event of an ignited rupture failure. Pipeline incident reports, located in the public domain, were reviewed and provide the basis for evaluating the validity of the proposed affected area equation. The correlation suggests that the simple equation provides a credible estimate of affected area.

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RESEARCH SUMMARY

Title	A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines
Contractor(s)	C-FER Technologies
GRI-Contract Number	8174
Principal Investigator(s)	Mark J. Stephens
Report Type	Topical Report
Objective State	To develop a simple and defendable approach to sizing the ground area potentially affected by the failure of a high-pressure natural gas pipeline.
Technical Perspective	The rupture of a high-pressure natural gas pipeline can lead to outcomes that can pose a significant threat to people and property in the immediate vicinity of the failure location. The dominant hazard is thermal radiation from a sustained fire and an estimate of the ground area affected by a credible worst-case event can be obtained from a model that characterizes the heat intensity associated with rupture failure of the pipe where the escaping gas is assumed to feed a fire that ignites very soon after line failure.
Technical Approach	An equation has been developed that relates the diameter and operating pressure of a pipeline to the size of the affected area in the event of a credible worst-case failure event. The model upon which the hazard area equation is based consists of three parts: 1) a fire model that relates the rate of gas release to the heat intensity of the fire; 2) an effective release rate model that provides a representative steady-state approximation to the actual transient release rate; and 3) a heat intensity threshold that establishes the sustained heat intensity level above which the effects on people and property are consistent with the adopted definition of a High Consequence Area (HCA).
Results	For methane with an HCA threshold heat intensity of 5,000 Btu/hr ft^2, the hazard area equation is given by: $r = 0.685\sqrt{p\,d^2}$ where r is the hazard area radius (ft), d is the line diameter (in), and p is the maximum operating pressure (psi).
Project Implications	Natural gas transmission line operators will provide periodic assurances that their pipelines are safe. The Federal code 49CFR192 mandates increased wall thickness thereby reducing the corrosion and mechanical damage risks as the population density increases. The definition of High Consequence Areas is expected to require additional protection for people with limited mobility such as day care centers, old age homes, and prisons. This report suggests the definition for the HCA area of increased protection be set by two parameters, the pipe diameter and it's operating pressure.

TABLE OF CONTENTS

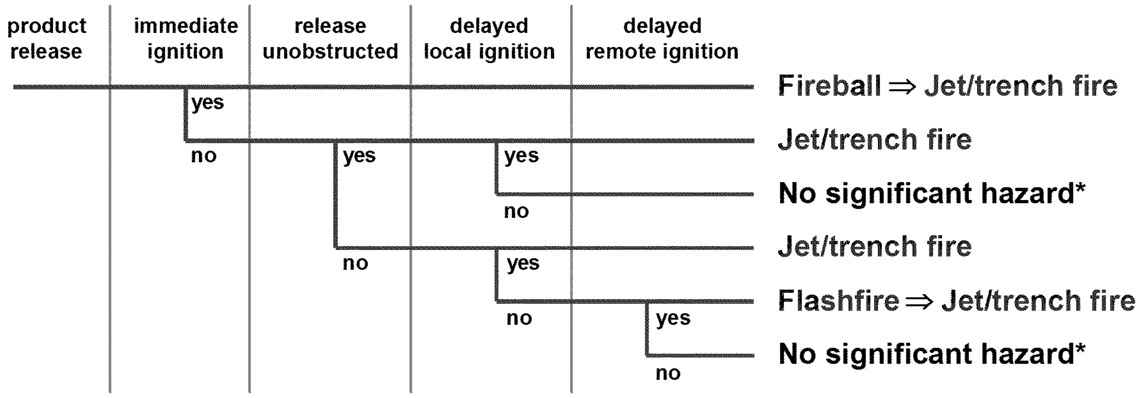
1. INTRODUCTION

1.1 Scope and Objective

This report summarizes the findings of a study conducted by C-FER Technologies (C-FER), under contract to the Gas Research Institute (GRI), to develop a simple and defendable approach to sizing the ground area potentially affected by the failure of a high-pressure natural gas pipeline. This work was carried out at the request of the Integrity Management and Systems Operations Technical Advisory Group (IM&SO TAG), a committee of GRI.

1.2 Technical Background

The failure of a high-pressure natural gas pipeline can lead to various outcomes, some of which can pose a significant threat to people and property in the immediate vicinity of the failure location. For a given pipeline, the type of hazard that develops, and the damage or injury potential associated with the hazard, will depend on the mode of line failure (*i.e.*, leak vs. rupture), the nature of gas discharge (*i.e.*, vertical vs. inclined jet, obstructed vs. unobstructed jet) and the time to ignition (*i.e.*, immediate vs. delayed). The various possible outcomes are summarized in Figure 1.1.



**** ignoring hazard potential of overpressure and flying debris***

Figure 1.1 Event tree for high pressure gas pipeline failure (adapted from Bilo and Kinsman 1997).

For gas pipelines, the possibility of a significant flash fire resulting from delayed remote ignition is extremely low due to the buoyant nature of the vapor, which generally precludes the formation of a persistent flammable vapor cloud at ground level. The dominant hazard is, therefore, thermal radiation from a sustained jet or trench fire, which may be preceded by a short-lived fireball.

In the event of line rupture, a mushroom-shaped gas cloud will form and then grow in size and rise due to discharge momentum and buoyancy. This cloud will, however, disperse rapidly and a quasi-steady gas jet or plume will establish itself. If ignition occurs before the initial cloud disperses, the flammable vapor will burn as a rising and expanding fireball before it decays into a sustained jet or trench fire. If ignition is slightly delayed, only a jet or trench fire will develop. Note that the added effect on people and property of an initial transient fireball can be accounted for by overestimating the intensity of the sustained jet or trench fire that remains following the dissipation of the fireball.

A trench fire is essentially a jet fire in which the discharging gas jet impinges upon an opposing jet and/or the side of the crater formed in the ground. Impingement dissipates some of the momentum in the escaping gas and redirects the jet upward, thereby producing a fire with a horizontal profile that is generally wider, shorter and more vertical in orientation, than would be the case for a randomly directed and unobstructed jet. The total ground area affected can, therefore, be greater for a trench fire than an unobstructed jet fire because more of the heat-radiating flame surface will typically be concentrated near the ground surface.

An estimate of the ground area affected by a credible worst-case failure event can, therefore, be obtained from a model that characterizes the heat intensity associated with rupture failure of the pipe, where the escaping gas is assumed to feed a sustained trench fire that ignites very soon after line failure.

Because the size of the fire will depend on the rate at which fuel is fed to the fire, it follows that the fire intensity and the corresponding size of the affected area will depend on the effective rate of gas release. The release rate can be shown to depend on the pressure differential and the hole size. For guillotine-type failures, where the effective hole size is equal to the line diameter, the governing parameters are, therefore, the line diameter and the pressure at the time of failure. Given the wide range of actual pipeline sizes and operating pressures, a meaningful fire hazard model should explicitly acknowledge the impact of these parameters on the area affected.

1.3 Report Organization

The hazard model developed to relate the area potentially affected by a failure to the diameter and pressure of the pipeline is described in Section 2.0. Validation of the proposed hazard area model, based on historical data from high-pressure gas pipeline failure incidents in the United States and Canada, is presented in Section 3.0.

2. HAZARD MODEL

2.1 Overview

An equation has been developed that relates the diameter and operating pressure of a pipeline to the size of the area likely to experience high consequences in the event of a credible worst-case failure event. The hazardous event considered is a guillotine-type line rupture resulting in double-ended gas release feeding a trench fire that is assumed to ignite soon after failure.

The hazard model upon which the hazard area equation is based consists of three parts: 1) a fire model that relates the rate of gas release to the heat intensity of the fire as a function of distance from the fire source; 2) an effective release rate model that provides a representative steady-state approximation to the actual transient release rate; and 3) a heat intensity threshold that establishes the sustained heat intensity level above which the effects on people and property are consistent with the definition of a high consequence area. Note that in the context of this study, an HCA is defined as the area within which the extent of property damage and the chance of serious or fatal injury would be expected to be significant in the event of a rupture failure.

The basis for each model, and any underlying assumptions, are described in Sections 2.2 through 2.4. The hazard area equation obtained by combining the model components is described in Section 2.5.

2.2 Fire Model

A jet flame can be idealized as a series of point source heat emitters spread along the length of the flame (see Figure 2.1). Each point source can be is assumed to radiate an equal fraction of the total heat with the heat flux I_i at a given location resulting from point source i being given by (Technica 1988):

$$I_i = \frac{\eta X_g Q_{eff} H_c}{4 n_p \pi x_i^2} \qquad [2.1]$$

where H_c = heat of combustion (constant for given product) ≅ 50,000 kJ/kg for methane;
η = combustion efficiency factor = 0.35;
X_g = emissivity factor = 0.2;
n_p = number of point sources;
Q_{eff} = effective gas release rate; and
x_i = radial distance from heat source i to the location of interest.

The total heat flux reaching a given point is obtained by summing the radiation received from each point source emitter.

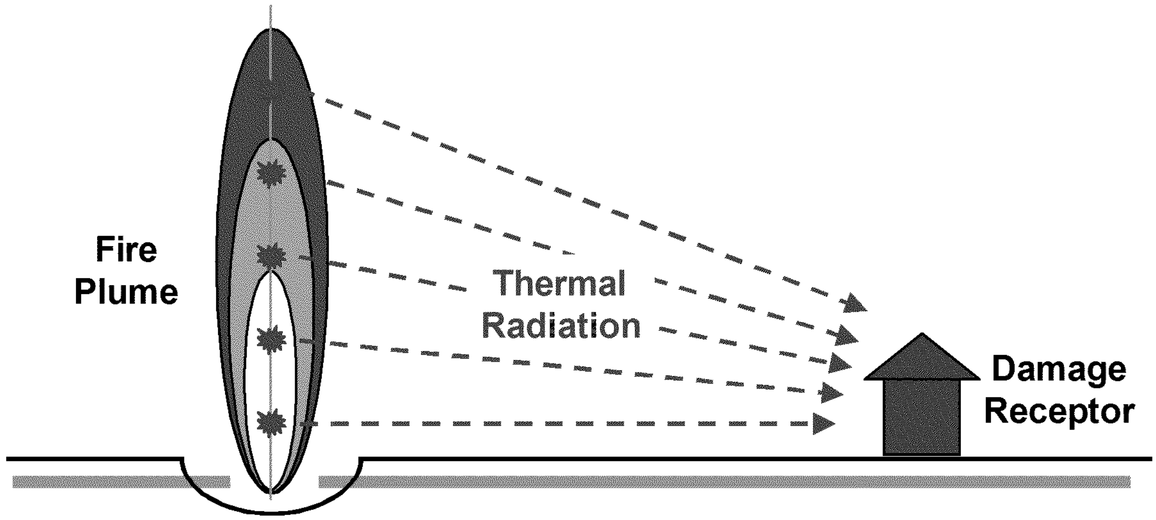


Figure 2.1 Conceptual fire hazard model.

A simplifying assumption, that generally yields a conservative estimate of the total heat flux received by ground level damage receptors, involves collapsing the set of heat emitters into a single point source emitter located at ground level (see Figure 2.2).

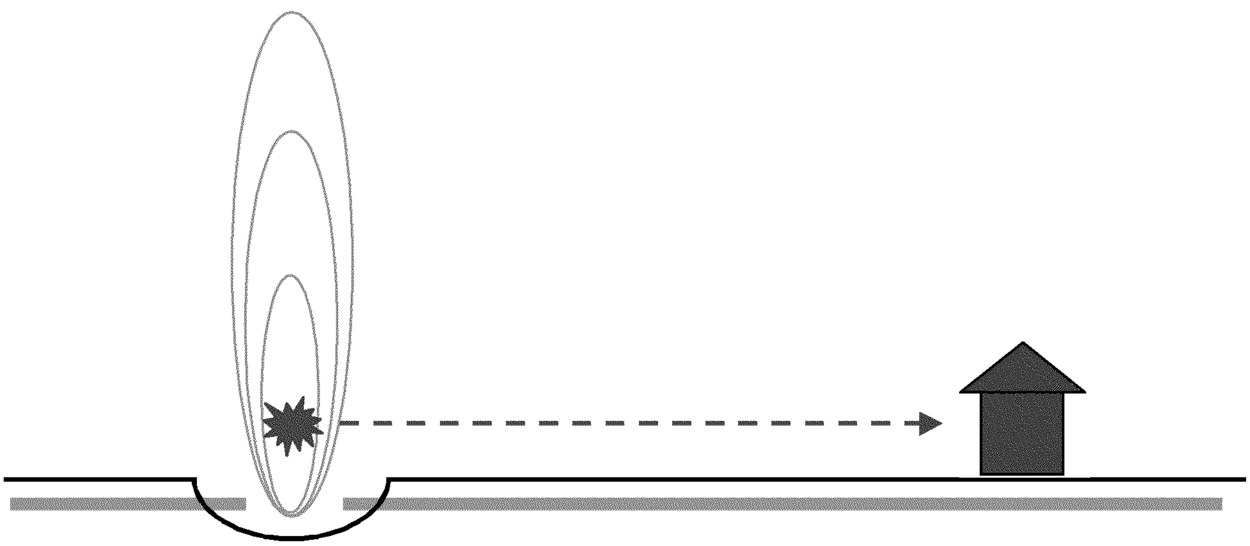


Figure 2.2 Simplified fire hazard model.

The resulting equation for the total heat flux I at a horizontal distance of r from the fire center is given by:

$$I = \frac{\eta X_g Q_{eff} H_c}{4\pi r^2} \qquad [2.2]$$

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This simplification is, in some respects, more consistent with the geometry of a trench fire which, due to the jet momentum dissipation (see Section 1.2), concentrates more of the heat-radiating flame surface near ground level. Note, however, that while a ground-level point source model represents a conservative approximation to a vertically-oriented jet flame or trench fire, this conservatism is partially offset by the fact that the model does not explicitly account for the possibility of laterally-oriented jets and/or the effects of wind on the actual position of the fire center relative to the center of the pipeline.

Note, also, that for a single point source emitter located at ground level directly above the pipeline, the locus of points receiving a heat flux of I defines a circular area of radius r centered on the pipeline. Thermal radiation hazard zones of increasing impact severity are, therefore, described by concentric circles centered on the pipeline having radii that correspond to progressively higher heat fluxes.

The adopted heat flux versus distance relationship given by Equation [2.2] represents an extension of the widely recognized flare radiation model given in API RP 521 (API 1990). It can be shown to be less conservative than the API flare model (*i.e.*, it gives lower heat intensity estimates at a given distance) but this should not be considered surprising since the API model is widely recognized to be conservative (Lees 1996).

The adopted model is also preferred over some of the more generic, multi-purpose models available for industrial fire hazard analysis because it acknowledges factors, ignored by other models, that play a significant role in mitigating the intensity of real-world jet fire events. In particular, it accounts for the incomplete combustion of the escaping gas stream (through the combustion efficiency factor η), and it acknowledges (through the emissivity factor X_g) that a significant portion of the radiant heat energy will be absorbed by the atmosphere before it can reach targets at any significant distance from the flame surface.

2.3 Effective Release Rate Model

The rate of gas release from a full-bore line rupture varies with time. Within seconds of failure, the rate of release will have dropped to a fraction of the peak initial value and over time the release rate will decay even further. This tendency for rapid release rate decay is illustrated in Figure 2.3, which shows how the rate would be expected to vary with time for two representative line diameter and operating pressure combinations. The relative release rate estimates shown in the figure were calculated using a non-dimensional rate decay model presented in a study by the Netherlands Organization of Applied Scientific Research, Division of Technology for Society (TNO 1982) which is based on realistic gas flow and decompression characteristics and which acknowledges both the compressibility of the gas and the effects of pipe wall friction.

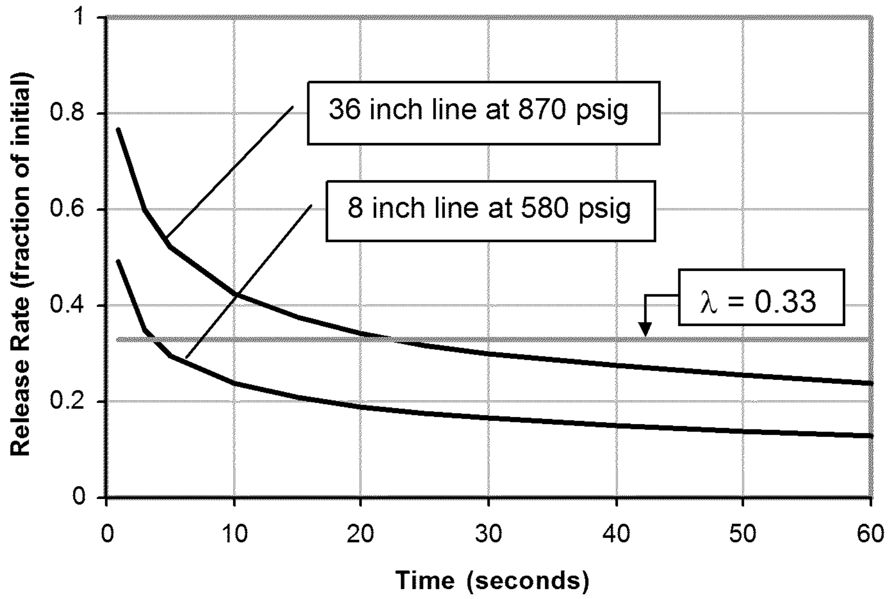

Figure 2.3 Release rate decay.

The peak initial release rate from the single end of a full-bore line rupture can be estimated using the widely recognized gas discharge equation given by the Crane Co. (1981) for sonic or choked flow through an orifice:

$$Q_{in} = C_d \frac{\pi d^2}{4} p \frac{\varphi}{a_0} \qquad [2.3a]$$

where φ = flow factor = $\gamma \left(\dfrac{2}{\gamma + 1} \right)^{\frac{\gamma+1}{2(\gamma-1)}}$; [2.3b]

a_0 = sonic velocity of gas = $\sqrt{\dfrac{\gamma R T}{m}}$; [2.3c]

C_d = discharge coefficient $\cong$ 0.62;
γ = specific heat ratio of gas $\cong$ 1.306 for methane;
R = gas constant = 8,310 J/(kg mol)/K;
T = gas temperature $\cong$ 288 K or 15 C;
m = gas molecular weight $\cong$ 16 kg/mol for methane;
d = effective hole diameter $\cong$ line diameter; and
p = pressure differential $\cong$ line pressure.

Given that the release rate is highly variable, it follows that the size and intensity of the associated fire will also vary with time and the peak intensity of the fire will depend on exactly when ignition occurs. The hazard model developed herein accounts for the above by approximating the transient jet or trench fire as a steady state fire that is fed by an *effective* release rate. The effective release rate is a fractional multiple of the peak initial release rate that can be used to obtain estimates of sustained heat flux that are comparable to those obtained from a more realistic transient fire model that assumes a slight delay in ignition time.

For a guillotine-type failure of a pipeline resulting in double-ended release, the effective release rate that is assumed to feed a steady-state fire is given by:

$$Q_{eff} = 2\lambda Q_{in} = 2\lambda C_d \frac{\pi d^2}{4} p \frac{\varphi}{a_0} \qquad [2.4]$$

where λ is the release rate decay factor and the factor of 2 acknowledges that gas will be escaping from both failed ends of the pipeline.

In general, the most appropriate value for the release rate decay factor will depend on the size of pipeline being considered, the pressure in the line at the time of failure, the assumed time to ignition, and the time period required to do damage to property or cause harm to people. Given that even immediate ignition will require several seconds for the establishment of the assumed radiation conditions and given further that a fatal dose of thermal radiation can be received from a pipeline fire in well under 1 minute (see Section 2.4), it follows from Figure 2.3 that a rate decay factor in the range of 0.2 to 0.5 will likely yield a representative steady state approximation to the release rate for typical pipelines.

In a study of the risks from hazardous pipelines in the United Kingdom conducted by A. D. Little Ltd. (Hill and Catmur 1995), the authors report using a release rate decay factor of 0.25. A slightly more conservative value for λ of 0.33 has been adopted herein to ensure that the sustained fire intensity associated with nearly immediate ignition of fires associated with large diameter pipelines will not be underestimated (see Figure 2.3). Given that anecdotal information on natural gas pipeline failures suggests that the time to ignition may typically be in the range of 1 to 2 minutes (as in the Edison, New Jersey incident of 1994), the adopted release rate decay factor will likely yield an effective release rate estimate that overestimates the actual rate for the full duration of a typical gas pipeline rupture fire.

2.4 Heat Intensity Threshold

For people, the degree of harm caused by thermal radiation is usually estimated using a model that relates the chance of burn injury or fatality to the thermal load received where the thermal load L_p is given by an equation of the form (Lees 1996):

$$L_p = t\, I^n \qquad [2.5]$$

where t is the exposure duration, I is the heat flux and n is an index.

Various recognized thermal load vs. effect models based on Equation [2.5] are summarized in Table 2.1 together with calculated estimates of the exposure times required to reach various conditions of injury and mortality for persons exposed to specified heat intensity levels. If it is assumed that within a 30 second time period an exposed person would remain in their original position for between 1 and 5 seconds (to evaluate the situation) and then run at 5 mph (2.5 m/s) in the direction of shelter, it is estimated that within this period of time they would travel a distance of about 200 ft (60 m). On the further assumption that, under typical conditions, a person can reasonably be expected to find a sheltered location within 200 ft of their initial position, a 30 second exposure time is considered credible and is, therefore, adopted as the reference exposure time for people outdoors at the time of failure.

Radiation Intensity or Heat Flux (Btu/hr ft^2)	Radiation Intensity or Heat Flux (kW/m^2)	Time to Burn Threshold (Eisenberg et al. 1975) $t^*I^{1.15} = 195$	Time to Blister Threshold - lower[1] (Hymes 1983)[2] $t^*I^{1.33} = 210$	Time to Blister Threshold - upper[1] (Hymes 1983)[2] $t^*I^{1.33} = 700$	Time to 1% Mortality (Hymes 1983)[2] $t^*I^{1.33} = 1060$	Time to 50% Mortality (Hymes 1983)[2] $t^*I^{1.33} = 2300$	Time to 100% Mortality[3] (Bilo & Kinsman 1997) $t^*I^{1.33} = 3500$
1600	5.05	30.3	24.4	81.3	123.1	267.1	406.4
2000	6.31	23.5	18.1	60.4	91.5	198.5	302.1
3000	9.46	14.7	10.6	35.2	53.4	115.8	176.2
4000	12.62	10.6	7.2	24.0	36.4	79.0	120.2
5000	15.77	8.2	5.4	17.9	27.0	58.7	89.3
8000	25.24	4.8	2.9	9.6	14.5	31.4	47.8
10000	31.55	3.7	2.1	7.1	10.8	23.3	35.5
12000	37.85	3.0	1.7	5.6	8.4	18.3	27.9

Note: 1) Hymes gives a thermal load range (210 to 700) rather than a single value for blister formation
2) the thermal load values given by Hymes are based on a revised interpretation of the results obtained by Eisenberg et al.
3) Bilo and Kinsman assume that 100% mortality corresponds to a lower bound estimate of the thermal load associated with the spontaneous ignition of clothing

Table 2.1 Effects of thermal radiation on people.

The exposure time estimates closest to this reference time are highlighted in Table 2.1 for each different thermal load effect. Note that the onset of burn injury within the reference exposure time is associated with a heat flux in the range of 1,600 to 2,000 Btu/hr ft^2 (5 to 6.3 kW/m^2), depending on the burn injury criterion. The chance of fatal injury within the reference exposure time becomes significant at a heat flux of about 5,000 Btu/hr ft^2 (15.8 kW/m^2), if the significance threshold is taken to be a 1% chance of mortality (*i.e.,* 1 in 100 people directly exposed to this thermal load would not be expected to survive).

For property, as represented by a wooden structure, the time to both piloted ignition (*i.e.,* with a flame source present) and spontaneous ignition (*i.e.,* without a flame source present) can also be estimated as a function of the thermal load received. For buildings, the thermal load L_b is given by an equation of the form (Lees 1996):

$$L_b = (I - I_x)t^n \qquad [2.6]$$

where I_x is the heat flux threshold below which ignition will not occur.

Models based on Equation [2.6], developed from widely cited tests as re-interpreted by the UK Health and Safety Executive (Bilo and Kinsman 1997), are summarized in Table 2.2 together with calculated estimates of the exposure times required for both piloted and spontaneous ignition at selected heat intensity levels.

Radiation Intensity or Heat Flux ($Btu/hr\ ft^2$)	Radiation Intensity or Heat Flux (kW/m^2)	Time to Piloted Ignition[1] (Bilo & Kinsman 1997) $(I-14.7)*t^{0.667}=118.6$	Time to Spontaneous Ign.[1] (Bilo & Kinsman 1997) $(I-25.6)*t^{0.8}=167.6$
4000	12.62	no ignition	no ignition
5000	15.77	1162.3	no ignition
8000	25.24	37.8	no ignition
10000	31.55	18.7	65.0
12000	37.85	11.6	26.3
Note: 1) based on experiments on American whitewood			

Table 2.2 Effects of thermal radiation on wooden structures.

From Table 2.2 it can be seen that 5,000 Btu/hr ft^2 (15.8 kW/m^2), corresponds to piloted ignition after about 20 minutes (1,200 seconds) of sustained exposure. The table further shows that spontaneous ignition is not possible at this heat intensity level. It is therefore assumed that this heat intensity represents a reasonable estimate of the heat flux below which wooden structures would not be destroyed, and below which wooden structures should afford indefinite protection to occupants.

Note that the model employed for estimating the effects of thermal radiation on property explicitly considers the duration of exposure required to cause ignition. Some earlier wood ignition models, which appear to be the basis for the often cited 4,000 Btu/hr ft^2 (12.6 kW/m^2) threshold for piloted wood ignition, are in fact associated with an almost indefinite time to ignition and are, therefore, considered to be overly conservative given the transient (decaying) nature of real pipeline rupture fires.

In light of the above, if a high consequence area is defined as the area within which both the extent of property damage and the chance of serious or fatal injury would be expected to be significant, it follows that this area can reasonably be defined by a heat intensity contour corresponding to a threshold value below which:

- property, as represented by a typical wooden structure, would not be expected to ignite and burn;
- people located indoors at the time of failure would likely be afforded indefinite protection; and
- people located outdoors at the time of failure would be exposed to a finite but low chance of fatality.

The information presented on thermal load effects suggests that below 5,000 Btu/hr ft^2, a wooden structure would not be expected to burn and it, thereby, affords indefinite protection to sheltered persons. Also, this heat intensity level corresponds to approximately a 1 percent chance of fatality for persons exposed for a credible period of time before reaching shelter. A heat flux of 5,000 Btu/hr ft^2 has, therefore, been adopted as the threshold heat intensity for the purpose of sizing a high consequence area.

2.5 Hazard Area Equation

Substituting the expression developed for the effective release rate (Equation [2.4]) into the heat intensity versus distance formula (Equation [2.2]), replacing all constants and rearranging gives the following expression for the radial distance to locations where the heat flux is equal to the threshold value:

$$r = \sqrt{\frac{2348\, p\, d^2}{I_{th}}} \quad \text{(ft)} \qquad [2.7]$$

where I_{th} = threshold heat intensity (Btu/hr/ft^2);
p = line pressure (psi); and
d = line diameter (in).

For a threshold heat intensity of 5,000 Btu/hr ft^2, the above expression reduces to:

$$r = 0.685\sqrt{p\, d^2} \qquad [2.8]$$

Equation [2.8] can, therefore, be used to estimate the radius of a circular area surrounding the assumed point of line failure within which the impact on people and property would be expected to be consistent with the adopted definition of a high consequence area.

Hazard area radii, as calculated using Equation [2.8] are plotted in Figure 2.4 as a function of line diameter and operating pressure. The figure shows that, for pipelines operating at pressure levels in the range of 600 to 1,200 psi, the calculated hazard area radius ranges from under 100 ft for small diameter lines to over 1,100 ft for large diameter lines.

Note that the concept of relating the potential hazard area to the line diameter and operating pressure is not new. An approach similar to that described herein has been an integral part of the high pressure gas transmission pipeline code in the United Kingdom since 1977 (Knowles *et al*. 1978 and IGE 1993). The standard as developed in the United Kingdom incorporates the concept of a Building Proximity Distance (BPD), multiples of which serve to define development exclusion zones and establish the pipeline corridor width for the purpose of determining Location Class. The BPD is calculated directly from the line diameter and the maximum operating pressure.

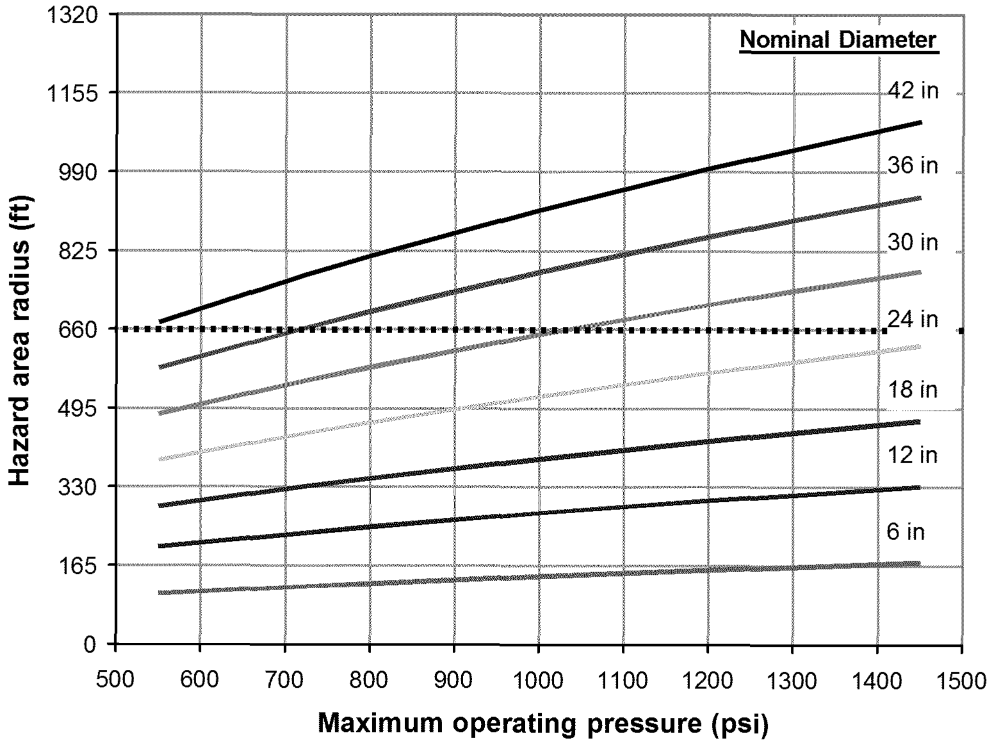

Figure 2.4 Proposed hazard area radius as a function of line diameter and pressure.

3. MODEL VALIDATION

Pipeline incident reports, located in the public domain, were reviewed to provide a basis for evaluating the validity the proposed hazard area model given by Equation [2.8]. The data sources reviewed included reports on pipeline incidents in the United States prepared by the National Transportation Safety Board (NTSB) going back to 1970, and similar reports on incidents in Canada prepared by the Transportation Safety Board (TSB) going back to 1994. Note that the information extracted from these reports required some interpretation due to differences in the way the information was reported. The processed data together with hazard area estimates obtained using Equation [2.8] are summarized in Figure 3.1. A summary of the information that forms the basis for Figure 3.1 is given in Table 3.1.

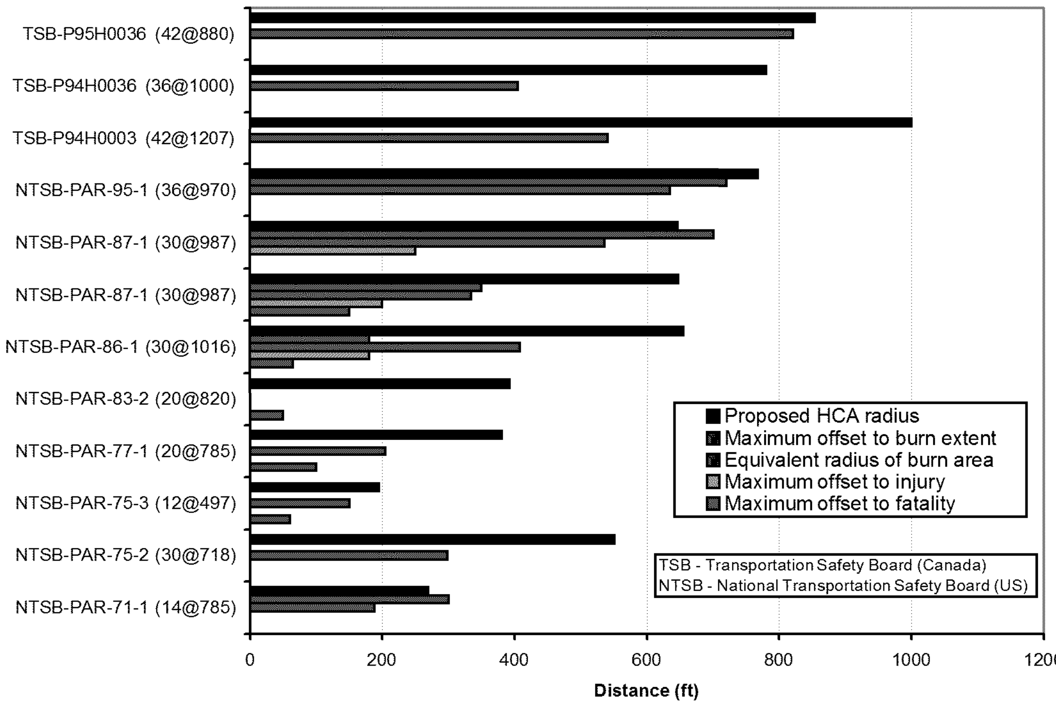

Figure 3.1 Comparison between actual incident outcomes and the proposed hazard area model.

In interpreting the incident outcomes summarized in Figure 3.1 note the following:

- the *equivalent radius of burn area* is the radius of a circle having an area equal to the reported area of burnt ground;
- the *maximum offset to burn extent* is the maximum reported of inferred lateral extent of burnt ground measured perpendicular to a line tracing the alignment of the pipeline prior to failure; and
- the *maximum offset to injury/fatality* is the maximum reported or inferred distance to an injury/fatality again measured perpendicular to a line tracing the alignment of the pipeline prior to failure.

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Figure 3.1 shows that in every case the hazard area calculated using the proposed equation is greater than the actual reported area of burnt ground. In addition, with the sole exception of one of the incidents reported in NTSB-PAR-87-1, the radius obtained from the hazard area equation conservatively approximates the maximum lateral extent of the burn zone. Finally, in all cases the calculated hazard zone radius significantly exceeds the maximum reported offset distance to injury or fatality.

Note, however, that whereas the interpretation of reported burn areas and burn distances is obvious, caution should be exercised in interpreting maximum offset distances to injury and fatality. Given that most of the incidents occurred in sparsely populated areas, the reported injury and fatality offsets are more indicative of where people happened to be at the time of failure rather than being representative of the maximum possible distances to injury or fatality for the incident in question.

Acknowledging the uncertainty associated with interpreting reported offsets to injury and fatality, the balance of information still overwhelmingly indicates that the proposed hazard area radius equation provides a reasonable, if somewhat conservative, estimate of the zone of high consequence.

It is thought that one of the main reasons for the apparent conservatism in the proposed hazard area model is that it is based on an effective sustained release rate that is consistent with the assumption of almost immediate ignition. The actual time to ignition for many of the reported incidents is probably longer (see incident notes in Table 3.1) making the effective release rate approximation conservative.

Date	Report	Location	Incident	Damage	Maximum Burn Distance	Diameter (in)	Pressure (psi)
1969	NTSB-PAR-71-1	near Houston, Texas	Rupture at 3:40 p.m. on September 9th, explosive ignition 8 to 10 minutes after failure.	Burned area 370 ft long by 300 ft wide (all to one side). Houses destroyed by blast to 250 ft, heat damage to 300 ft, 106 homes damaged, 9 injuries, and 0 fatalities.	300 ft	14	789
1974	NTSB-PAR-75-2	near Bealeton, Virginia		Burned area 700 ft by 400 ft.		30	718
1974	NTSB-PAR-75-3	near Farmington, New Mexico	Rupture at 3:45 a.m. on March 15th, ignition soon after failure.	Earth charred within a 300 ft diameter circle, 3 fatal injuries (within 60 ft offset)		12.75	497
1976	NTSB-PAR-77-1	Cartwright, Louisiana	Rupture at 1:05 p.m. on August 9th, ignited within seconds	Burn area 3 acres (implies a 200 ft radius circle), 6 fatalities (within about 100 ft offset) and 1 injury.		20	770
1982	NTSB-PAR-83-2	Hudson, Iowa		5 fatalities (within 150 ft, less than 50 ft offset).		20	820
1984	NTSB-PAR-86-1	near Jackson, Louisiana	Rupture at 1:00 p.m. on November 25th, ignition soon after failure.	Burned area 1450 ft long by 360 ft wide (furthest fire extent 950 ft), 5 fatalities (within 65 ft, 0 ft offset), and 23 injuries (within 800 ft,180 ft offset).	Offset 180 ft. Distance 950 ft.	30	1016
1985	NTSB-PAR-87-1	near Beaumont, Kentucky	Rupture at 9:10 p.m. on April 27th, ignition soon after failure.	Burned area 500 ft wide by 700 ft long. 2 houses, 3 house trailers and numerous other structures and equipment destroyed. 5 fatalities due to smoke inhalation in house 318 ft from rupture (150 ft offset), 3 people burned running from house 320 ft from rupture (200 ft offset) one hospitalized with 2nd degree burns.	Offset 350 ft. Distance 500 ft.	30	990
1986	NTSB-PAR-87-1	near Lancaster Kentucky	Rupture at 2:05 a.m. on February 21st, ignition soon after failure.	Burned area 900 ft by 1000 ft. 2 houses, 1 house trailer and numerous other structures and equipment destroyed. 3 people burned running from house 280 ft from rupture (requiring hospitalization), 5 others received minor burn injuries running from dwellings between 200 and 525 ft from rupture (250 ft offset).	Offset 700 ft. Distance 800 ft.	30	987
1994	NTSB-PAR-95-1	Edison, New Jersey	Rupture at night on March 23rd, ignition within 1 to 2 minutes after failure.	Burned area 1400 ft long by 900 ft wide. Fire damage to dwelling units up to 900 ft from rupture, dwelling units at 500 ft and beyond caught fire between 7 to 10 minutes after failure, no fatalities but 58 injuries.	Offset 720 ft. Distance 960 ft.	36	970
1994	TSB Report No. P94H0003	Maple Creek, Saskatchewan	Rupture at 7:40 p.m. on February 14th, ignition soon after failure.	Fire burn area 21.0 acres (8.5 hectares).		42	1207
1994	TSB Report No. P94H0036	Latchford, Ontario	Rupture at 7:13 a.m. on July 23rd, ignition soon after failure.	Fire burn area 11.8 acres (4.77 hectares), heat-affected area 18.6 acres (7.52 hectares).		36	1000
1995	TSB Report No. P95H0036	Rapid City, Manitoba	Rupture of 42 inch line at 5:42 a.m. on July 29th, ignition soon after failure leading to rupture and fire on adjacent 36 inch line at 6:34 a.m.	Fire burn area 48.5 acres (19.6 hectares), heat-affected area 198 acres (80 hectares).		42	880

Table 3.1 Summary of relevant North American pipeline failure incident reports.

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ATTACHMENT 11

C-Fer Technologies letter to PG&E, "Adaptation of C-FER PIR Formula to Alternative Hazard Assessments," dated March 10, 2011.

CONFIDENTIAL DUE TO NAMES

ATTACHMENT 12

ENengineering Report prepared for PG&E, "Industry Survey of Operation Natural Gas Pipeline Operators on Automatic Valves," dated April 4, 2011.

CONFIDENTIAL DUE TO NAMES

ATTACHMENT 13

Robert J Eiber Consultant Inc and Kiefner and Associates, "Review of Safety Consideration for Natural Gas Pipeline Block Valve Spacing," July 2010.

Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing

To

ASME Standards Technology, LLC

From

Robert J Eiber Consultant Inc and Kiefner and Associates

July 2010

Robert J Eiber Consultant Inc
4062 Fairfax Dr.
Columbus, Ohio 43220

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EXECUTIVE SUMMARY

The goals of this review are 1) to examine prior studies that have been conducted to define the relationship of block valves on gas transmission pipelines to public safety, 2) to assess the relationship of valve spacing and valve operator type on public safety, and 3) to evaluate if valve spacing/valve operator type, or valve location can improve public safety. The presence, location, and the spacing of main line block valves were found to have no impact on the likelihood or consequences of a failure on a natural gas transmission pipeline. Even if the valves are closed at the start of an incident, calculations and historical records confirm that natural gas pipelines require more than an hour to decompress (depressurize). The only quantifiable impact of type of valve operator, which controls the time to close a valve after an incident, is the economic impact of gas loss, but this does not produce a safety impact. The most severe consequences to the public occur in the first moments after incident initiation, thus valve spacing, valve location and valve closure time (valve operator type) do not affect public safety.

This review found that all of the prior research studies, the examination of the PHMSA incident database, and examination of NTSB gas transmission pipeline incidents indicate that main line block valve spacing on natural gas transmission pipelines is not related to public safety. Valves are useful for maintenance and line modification but they do not control or affect public safety as the injuries and fatalities on gas transmission pipelines generally occur during the first 30 seconds after gas has been released from a pipeline. The NTSB incidents reviewed indicated that it took at least an hour after the rupture occurred for the natural gas to decompress and exhaust from the pipeline. This exists because a natural gas pipeline is not like a water pipe in a building where when the valve is closed the incompressible water stops flowing out of the pipe no matter how far the valve is from the pipe opening. Natural gas is compressed to about 70 to 100 atmospheres[a] for cross country transmission pipelines and it takes time for the decompression to occur. Calculations indicated that smaller diameter pipelines required longer decompression times; i.e., 12 inch (305 mm) diameter pipelines take about twice as long as a 36 inch (914 mm) diameter pipeline of the same length for a worst case full rupture condition due to wall friction effects

The review of the PHMSA incident database revealed that from 2002 to 2009 the data indicated that the total public damage cost does not correlate with time to make the area safe (related to the depressurization time) or the concentration of the released gas. The public damage correlates to the proximity of the workers/public and whether the gas ignites neither of which is controllable for the existing pipeline network. The most serious incidents with large property damage and the potential for injuries and fatalities involved early ignition of the natural gas. The examination of the time to make an area safe revealed that the largest public damage costs were associated with an incident that had a 3.5 hour "time to make the area safe" and a total public damage cost of 87.5 million dollars due to the close proximity of a power plant that was damaged by the ignited gas. The longest "time to make the area safe" was 116.8 hours and there was no public damage reported. Of the eleven highest total PHMSA incident costs, all but one had a "time to make the area safe" of less than 4 hours. The one exception had a "time to make the area safe" of 11 hours and had total damage costs of $6.22 million with only $3000 of public damage and no injuries or fatalities.

[a] The gas pressure in service pipelines to a house is about 1/10 of an atmosphere.

The review of the thirteen NTSB incident reports[b] on gas transmission pipelines indicated that the consequences of the incident reports examined would not have been changed if the valves had been closed at the instant of gas release or if the valves had been spaced closer together. In the incident with the closest spacing between valves (1.25 miles [2km]) twelve fatalities occurred and had the highest fatality count of all the NTSB incidents reviewed. This indicates that if the gas ignites as it is released, the flame will be present for the full time that it takes to blowdown the natural gas (fuel) in the pipeline.

Another reason that demonstrates valves are not safety items is that in all of the NTSB incidents, the injuries and fatalities occurred immediately or within 30 seconds after the first release of natural gas due to either debris, suffocation, or fire.

One problem identified when parallel pipelines are involved is management deciding which pipeline has experienced the incident. This occurred in 50 percent of the NTSB incidents reported. However, it must be remembered that when parallel pipelines exist they are linked together with valves and crossovers and the pressure drop on the ruptured line can be difficult to identify because all of lines show a pressure decrease due to the open crossovers[c]. A methodology is needed to help quickly identify which pipeline ruptured when parallel lines exit.

Overall, valve spacing has not been identified as a safety issue and valve spacing should be based on efficient operation and maintenance of the pipelines. The type of valve operator is not a safety factor. Valve operators take from minutes to almost an hour to close depending on the type and the combustion damage, injuries and fatalities have already occurred well before the time a valve can be closed.

This review indicated that external force damage remains the primary cause of death and injury. Therefore the most significant reduction in risk to the public can be achieved by operator application of an integrity management plan to their pipelines to prevent these third-party damage incidents from occurring.

[b] The other NTSB incident reports dealt with liquid pipelines, distribution pipelines, offshore pipelines, compressor stations and other miscellaneous situations.

[c] These open crossover pipelines allow equalization across all (up to seven) parallel lines in the same right of way.

REVIEW OF SAFETY CONSIDERATIONS FOR NATURAL GAS PIPELINE BLOCK VALVE SPACING

GOAL OF CURRENT REVIEW

The goal of this review is to:

1. Examine prior studies that have been conducted to define the issues associated with the spacing of block valves on gas transmission pipelines. The DOT PHMSA incident database has been examined to identify trends in the results of gas transmission pipeline incidents with regard to the effect of block valve spacing. The data for this review has also been obtained from prior studies of accidents, i.e., the National Transportation Safety Board (NTSB) detailed reports of prior gas pipeline accidents and the knowledge of the authors obtained from examination of numerous gas transmission pipeline failures. .
2. Assess the relationship of valve spacing and valve operator type on public safety,
3. Evaluate if there is a way that valve spacing/valve operator type, or valve location can be used to improve public safety including the following components:
   - the proximity of the public to the rupture location,
   - the concentration of released gas,
   - whether the gas ignites, and
   - the length of time required for the line to blow down.

The quantity and spacing of sectionalizing block valves has a significant impact on the construction cost of new pipeline systems and in responding to Location Class changes. Projects outside the US may consider use of standards other than ASME B31.8 where valve spacing allowances are more liberal than those in B31.8. B31.8 is also considering alternative design rules with increased stress levels justified by better quality design and engineering, where different valve spacing allowances may be appropriate. Revisions to the ASME Code can serve as a model for evolution of pipeline safety regulations in the US. Findings of this review will assist in defining the requirements for spacing and operator types for block valves in gas pipelines.

Prior reviews have examined research studies, incident reports, pipeline code requirements and engineering information about the interaction of pipeline operation and block valve controls and other available data to explore the relationship between block valve spacing, closure type and public safety. The prior research reviews have concluded that valve spacing is not a safety issue.

LITERATURE REVIEW AND BACKGROUND INFORMATION

Basis of ASME B31.8 Valve Spacing Requirements

Block valves in pipelines have been used since pipelines were first constructed. They have been required in pipeline codes (such as ASME B31.1.8 [predecessor to ASME B31.8 Committee] since 1952). In 1998, GRI collected information on the background and thinking that went into the development of the ASME B31.8 code and the information presented in that document[1] is included in the following paragraphs to define the basis for the original code requirement for block valves in gas transmission pipelines.

> *"Pipelines in place and constructed at the time the B31.1.8 Committee was initially meeting were predominately located in rural areas. The typical valve spacing in these*

areas was 18 to 20 miles (29 to 32 km), with accessibility being the primary factor for selecting the valve location. Based on economical and operating convenience, valves were installed about 20 miles (32 km) apart (on long pipeline segments such as 100 miles (160 km)) so that routine pipeline maintenance could be performed without having to blow the natural gas pressure down to one atmosphere and purge the methane with air for the entire pipeline between compressor stations. Some companies recognized the need for reduced distances in higher population areas, anticipating the need for more frequent isolation of valve sections to repair or replace pipeline defects.

Operating convenience, economics, and the need to limit adverse publicity during an incident were the primary motivations for establishing valve spacing recommendations in the Code. Although it is often perceived that valve spacing is based on minimizing the consequences of a pipeline incident, in actuality the majority of damage from a pipeline rupture occurs in the first few minutes after rupture (Sparks, 1995; Sparks, 1998). If the gas is ignited, being able to close the valve quickly has no effect on safety but may minimize negative public perception. Timely valve closure may not significantly reduce the amount of gas released to the atmosphere (Sparks, 1995, 1998). Safety is best addressed in the Code by assuring that the valve is accessible, and unexpected gas losses are minimized. The Code Committee surveyed industry practice in 1955 and suggested a requirement for valve spacing as a function of class location, as shown in the following tabulation. Specific intervals were designated to satisfy concerns of potential litigation associated with specifying valve spacing based on engineering judgment.

B31.1.8 Valve Spacing Requirements

Class Location	***Valve Spacing, miles***
1	*20*
2	*15*
3	*8*
4	*5*

The Code Committee intended the valve spacing recommendations to be used as guidelines, but for pipeline operators to also consider local conditions. For example, a valve located near a roadway is more readily accessible than one located in the middle of a pasture, cornfield, or swamp.

These spacing intervals reflected the current practices of the majority of pipeline operators in 1955, while also responding to governmental and public pressure for more valves in higher population areas.

The valve spacing requirements in 49 CFR Part 192 were based on recommendations in the B31.8 Code, but were rewritten to more clearly express the intended result (Docket OPS-3). The TPSSC[d] believed that valve placement was primarily an economic matter rather than a safety consideration. The increased number of valves required for higher population areas was based on minimizing the volume of gas released during maintenance activities and was not a decision based on public safety. The ASME B31.8 Code for pressure piping, (Gas Transmission and Distribution Piping) requirements in Paragraph 846 establish block valve spacing requirements based on Location Class. These requirements date to the 1955 Edition and were the basis for maximum valve

[d] PHMSA Technical Pipeline Safety Standards Committee

spacing restrictions in US pipeline regulations in 1968. A revision was made in the 2007 Edition of B3l.8 to allow other valve spacing based on operations and maintenance needs, but the fixed spacing remains as a legacy prescriptive option."

This background information demonstrates that it has been recognized that pipeline block valve spacing does not correlate to public safety in as much as it has no influence on whether an accident occurs and had little effect on the consequences since the largest magnitude of hazardous damage occurs immediately and then decreases with time. All the hazardous effect to the public occurs from the initial release of gas and ignition if it occurs. The primary objective in establishing block valve location is to facilitate maintenance. The B31.8 Section Committee has in the past proposed revisions to the code removing the valve spacing requirements, these have been unsuccessful because of the misperception that valve spacing is safety-related which is unsubstantiated by all the available government records and research data. This difference in perception versus historical and engineering data led to the current language found in ASME B31.8-2010 section 846.1 "Required Spacing of Valves". It adds the following new design requirements while still permitting grand-fathered spacing:

(a) In determining the number and spacing of valves to be installed, the operator shall perform an assessment that gives consideration to factors such as

- *(1)* the amount of gas released due to repair and maintenance blowdowns, leaks, or ruptures,
- *(2)* the time to blow down an isolated section,
- *(3)* the impact in the area of gas release (e.g., nuisance and any hazard resulting from prolonged blowdowns),
- *(4)* continuity of service,
- *(5)* operating and maintenance flexibility of the system,
- *(6)* future development in the vicinity of the pipeline, and
- *(7)* significant conditions that may adversely affect the operation and security of the line.

(b) In lieu of (a) above, the following maximum spacing between valves shall be used:

- *(1)* 20 miles (32 km) in areas of predominantly Location Class 1,
- *(2)* 15 miles (24 km) in areas of predominantly Location Class 2,
- *(3)* 10 miles (16 km) in areas of predominantly Location Class 3, and
- *(4)* 5 miles (8 km) in areas of predominantly Location Class 4. The spacing defined above may be adjusted to permit a valve to be installed in a location that is more accessible.

Review of Prior Studies on Valve Types and Spacing

1995 Report on Remote and Automatic Main Line Valve Technology Assessment

This study[2] reviewed the use of automatic and remote closing main line valves on gas transmission pipelines. Automatic main line valves are used in an attempt to mitigate the consequences of a gas pipeline rupture by achieving early shutoff of gas flowing into the ruptured section. They are driven closed by the pressure differential between a storage bottle (charged and maintained by line pressure) and the actual line pressure. If the line pressure drops quickly then the bottle pressure closes the valve. If the line pressure drops slowly, then the driving bottle pressure leaks back out the charging orifice and the valve only partially closes. While these systems are often effective in isolating line breaks, they sometimes fail to operate even on a full line break. In other cases, false closures are triggered by normal operational transients within the pipeline. False closures are a problem because they adversely affect continuity and reliability of service.

In order to minimize false closure, some companies have abandoned the use of automatic valves and have implemented remotely-controlled valves that rely on human judgment for actuation from a remote site such as a Gas Control Center. Unfortunately, the problems inherent in identifying which pipeline has experienced a line break plus the presence of other pipeline operating transients persist in the use of remotely-controlled valves. For the most part, the valves themselves and their operators function well if they are properly maintained and powered. However, the detection systems and control logic used by operators to trigger their closure have difficulty in distinguishing a pipeline break from other pipeline transient conditions. Typically, pipeline rate of pressure drop (ROPD) gas volumes, and/or static pressure is monitored for line break detection. When pipeline operational transients are comparable in magnitude to those resulting from a line break, detector sensitivity must be adjusted to prevent accidental closures which curtail customer service.

Digital simulation techniques appear to provide the only reliable means for the design analyses of complex looped pipeline systems with high transient levels due to compressors and intermittent branch loads. For simpler systems, computer simulations of typical systems have provided more generalized guidelines, although simulation is required to predict allowable threshold settings.

Blow down time for a ruptured line section depends primarily upon line length, initial pressure, break size, and valve closure times (up and downstream), and to a lesser degree upon pipe diameter, friction, gas temperature, and gas compositions. Even with immediate valve closure, however, blowdown times of an hour or more can be experienced for a full line break. In view of a range of ignition delay times of less than one to ten minutes, early valve closure still has no effect on preventing ignition. It also has no effect on the severity of the initial damage at the time of rupture.

1997 Report on a Survey of Design Rationale for Valve Usage in Various Design Codes
This survey[3] documented valve spacing, valve operator requirements, structure counts, and lengths and widths of the corridor used to define class location, design stress levels, and the associated rationale as used in natural gas pipeline codes in North America, Australia, and Europe to understand the basis for the existing code requirements and identify the rationale behind the requirements.

Fourteen pipeline design codes from ten countries were reviewed. The valve spacing requirements are of three types; 1) specified distances which vary by class location, 2) a limitation on the gas volume between valves, and 3) distances that are defined by the operational and maintenance requirements of a pipeline or are constant along a pipeline. Ten of the codes (71%) use class locations to define the requirements for the pipelines. The class location definitions are related to the density of the housing or population adjacent to the pipelines.

The rationale for the code requirements has been explored through a literature review coupled with visits and phone calls to knowledgeable persons. The valve spacing requirements appear to have been based on judgment and practical considerations for operations rather than specific technical data related to emergency responses.

2000 Report on Development of a Design Basis for Main Line Block Valve Spacing on Gas Transmission Pipelines
This report[4] objective was to develop a design basis for the spacing of block valves on gas transmission pipelines. Block valves have been generally considered to be required for safety isolation purposes in the event of an incident and for operation and maintenance. This study

clearly indicates that valve spacing has little or no effect on public safety and, therefore, valve placement should be determined by operational and maintenance needs and not population density.

Block valves do not prevent incidents, nor the resulting damages from occurring, but provide some control over the total amount of gas lost in an incident. The reduction in the lost gas as a function of block valve spacing and closure times was examined to determine the overall effect on injuries and fatalities, the risk to the public from thermal radiation in the event of a fire, the noise level, and the amount of gas released to the atmosphere.

The study results indicate that there are higher numbers of incidents, injuries and fatalities on a per 1,000 mile-year (1600 km-year) basis in the more highly populated regions along a pipeline (Class 3 and 4 locations than in Class 1 or 2 locations). The study also found that the injuries and fatalities were not related to the spacing of the valves but to the proximity of individuals to the point of gas release. The review of the U.S. incident data reveals that in incidents involving injuries and fatalities that the initial release of gas and/or ignition of the released gas causes the injury or fatality and, therefore, since valve spacing does not affect the initial release it plays no role in minimizing the consequence.

Further evidence of this is that injuries and fatalities have occurred in incidents where the valve spacing distance is the shortest (5 and 8 miles) (8 and 12.8 km)[e] as illustrated by incidents in Class 4 and 3 locations. For these data, the injuries and fatalities were the highest due to outside force incidents again validating that valve spacing played no role in minimizing the consequence.

The risk analysis conducted for this study found that, the risk of casualty to the public was independent of valve spacing as the injuries and fatalities occurred at the time of gas release when block valve closure does not affect the outflow of gas. Thus, pipeline valve placement is not a safety issue.

Noise levels were examined from the viewpoint of the initial shock wave by the release of rapidly decompressing methane gas and the jet noise associated with supersonic blowdown of a pipeline following a rupture. The consequences considered were damage to buildings and injury to humans. The result was that noise level was found to be independent of valve spacing.

No environmental regulations were identified that dictated valve spacing based on the volume of gas released to the atmosphere.

A cost benefit valve spacing model was developed to define optimum valve spacing. The model defines valve spacing based on economics of the total installed cost versus operational and maintenance constraints, conservation of gas, frequency of valve operations, and the probability of valves not sealing when fully closed. The results of the various scenarios examined suggest that valve spacing in the range of 5 to 20 miles (8 to 32 km) were cost effective.

In addition, a survey of the industry revealed that the desired valve spacing for operation and maintenance considerations ranges from 1 to more than 30 miles (1.6 to more than 48 km). Therefore, the cost beneficial model provides a rational and standardized engineering approach for locating valves.

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[e] In 1998, Title 49 CFR Part 192.179 was modified to change the valve spacing requirements from 20, 15, 8, and 5 miles for Class locations 1 through 4 to allow flexibility in valve spacing requirements if equivalent safety can be demonstrated.

The conclusion of the study was that the risk to the public is independent of valve spacing. Valve placement on gas transmission lines should be determined by operational and maintenance needs and not population density.

2005 White Paper on Equivalent Safety for Alternative Valve Spacing

This study[5] was conducted to address Class location changes that could cause the addition of main line block valves to assess whether the installation of additional block valves would increase the safety of a pipeline.

The study identified three major consequence scenarios due to a gas pipeline rupture: 1) thrown debris, 2) initial decompression pressure waves (peak noise) and 3) if ignited, thermal radiation energy from the exterior surface of the natural gas release. Most of the impact occurs within the first thirty seconds. This burst of energy is a function of internal pressure and is independent of both the block valve location and whether or not the valves are open or closed at the time of the rupture. The rupture initiates the release of a large volume of combustible natural gas, backfill and rock discharge over a predictable radius, and radiating a predictable peak sound pressure wave. The initial natural gas release quickly rises as a single plume above the smaller but still substantial discharge flow (natural gas is primarily methane and is lighter than air). If immediately ignited, the burning plume (as a mushroom shaped cloud) provides the maximum thermal radiation surface and flux density for about 30 seconds as the mushroom shape quickly rises due to natural buoyancy and the heat of combustion, and then quickly dissipates. If ignited even one minute later, the plume of natural gas will have dispersed to a significant extent, the outflow of natural gas will have reduced with time and thus the affected area will be greatly reduced.

Prior technical reports have concluded that installation of additional isolation valves to meet the proximity requirements of §192.179 after a pipe replacement due to a change in Class location provides little or no additional safety benefit to the public. GRI-98/0076 concluded that of 81 injury incidents reviewed (1970 to 1997 NTSB Incident Reports), 75 reported injuries at the initial rupture. Of the other six incidents, four occurred within 3 minutes of the rupture. It seems clear, therefore, that early valve closure time will have no effect on injuries sustained, and no effect on rupture severity. The benefit of "rapid-valve-closure" occurs "after the fact" as far as most injuries and damage are concerned. There is no evidence that prolonged blow down of a ruptured line causes injuries.

The valve proximity requirements specified in §192.179, are based on ASME B31.8 1968 edition. These requirements were not the result of safety considerations but of economic and practicality considerations. Installation of an additional valve as a result of a class location change provides no additional safety to the public.

Congress mandated and PHMSA updated the regulations to manage the increase in consequence that accompanies higher population density areas. Congress expects these are best managed by additional prevention and inspection practices. The pipeline safety regulations, therefore, provide for more frequent tests and inspections in higher class locations. In some cases, different inspection and testing techniques are specified.

In conclusion, the installation of additional sectionalizing block valves following a pipe replacement due to a class change to meet the proximity requirements of §192.179 provides no measurable increase in public safety. Therefore, the installation of additional valves in these situations should be left to the discretion of the operator.

2006 Study on the Safety Impact of Valve Spacing in Natural Gas Pipelines
This study[6] describes the findings of a scoping study conducted by Oak Ridge National Laboratory (ORNL) to assist U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) in assessing the safety impact of system valve spacing. Calculations of the pressures, temperatures, and flow velocities during a set of representative pipe depressurization transients were carried out using a one-dimensional numerical model with either ideal gas or real gas properties for the fluid. With both ideal gas and real gas properties, the high-consequence area radius for any resulting fire as defined by Stephens in GRI-00/0189 was evaluated as one measure of the pipeline safety. In the real gas case, a model for convective heat transfer from the pipe wall is included to assess the potential for shut-off valve failures due to excessively low temperatures resulting from depressurization cooling of the pipe. A discussion is also provided of some additional factors by which system valve spacing could affect overall pipeline safety.

The following conclusions can be drawn from this work:

1. Using an adaptation of the Stephens hazard radius criterion, valve spacing has a negligible influence on natural gas pipeline safety for the pipeline diameter, pressure range, and valve spacings considered in this study.
2. Over the first 30 seconds of the transient, pipeline pressure has a far greater effect on the hazard radius calculated with the Stephens criterion than any variations in the transient flow decay profile and the average discharge rate that would be associated with valve closing because of the time required for the gas in a pipeline to decompress after a valve is closed.

The scoping study report concluded, as have all of the other studies on block valve spacing, that the first 30 seconds of the gas release has a far greater effect on the hazard radius than the subsequent discharge rate which could be affected by valve closure or proximity. One factor discussed in this study, which has not been considered previously is the issue of low temperatures in the pipeline as a result of the gas cooling from the depressurization. The concern was raised as to whether this might affect the closing of a valve. In the 80 plus years of high pressure gas pipeline existence, this has never been observed and the probable explanation is that the transported gas is generally dry which eliminates the potential for ice to form and block the closure of a valve.

Green House Gas Emission Consideration Leading to Volume Limitations between Valves
Green house gas emission leading to global warming is a subject of debate. This subject is mentioned because a few countries (Netherlands, France, and Algeria) have a volume limitation on the gas stored between main line valves such as 90,000 and 300,000 cubic meters. The basis for the volume restrictions is unknown but it could be a prelude to controlling greenhouse gas emissions. The existing volume restrictions lead to valve spacing that is similar but somewhat shorter than the requirements in 49 CFR Part 192.

The issue of green house gas emissions was also discussed in regard to the Russian methane losses from their gas transmission pipelines.[7] The Russian natural gas industry is the world's largest producer and transporter of natural gas. This paper aims to characterize the methane emissions from Russian natural gas transmission operations, to explain projects to reduce these emissions, and to characterize the role of emissions reduction within the context of current green house gas (GHG) policy. It draws on the most recent independent measurements at all parts of the Russian long distance transport system made by the Wuppertal Institute in 2003 and combines these results with information from the US Natural Gas STAR Program on GHG mitigation options and economics . With this background the paper concludes that the CH_4

emissions from the Russian natural gas long distance network are at approximately 0.6 % of the natural gas delivered.

As background information on green house gases, they naturally blanket the earth and keep it about 33C (59F) warmer than it would be without these gases in the atmosphere. The green house gases are composed of 5% fluorocarbons, 6% Nitrous oxide, 13% methane, and 76% carbon dioxide.[8]. Carbon dioxide is emitted as humans exhale, burn fossil fuels for energy, and deforest the planet. Methane is another green house gas that stays in the atmosphere only 10 years but traps 20 times more heat than carbon dioxide. Carbon dioxide is recycled through photosynthesis - green plants transforming light energy into oxygen and rich organic compounds. Nitrous oxide is released naturally from oceans and bacteria in the soil. Nitrous oxide has at least a 100 year life in the atmosphere. Fluorocarbons used in the past to pressurize aerosol scans and refrigerators and air conditioners are now banned in the US and elsewhere.

It may be that in the future as an attempt to control the release of green house gases that a consideration in the placement of valves will be the volume of gas released in an accident. One way to implement this would be though the use of remote closing valves and their spacing.

Conclusion of Literature Review

The literature review revealed that the presence of main line block valves on a gas transmission pipeline have never provided increased safety to the public. The basis for this statement is that the injuries and fatalities that occur in connection with pipeline ruptures mainly occur in the first 30 seconds after the rupture and are associated with the initial release of gas and ignition, if it occurs. Due to the long decompression times associated with the gas volume decompressing as it flows out the openings in a pipeline, the presence of block valves on a pipeline can only restrain the entry of additional gas entering the pipeline and delay the blowdown of gas remaining in the pipeline. This occurs long after the injuries and fatalities have occurred. The blowdown of a gas pipeline takes time as the gas is initially compressed to at least 70+ atmospheres of compressed gas as it decompresses by decompressing all the way along the pipeline to the closed valves. This decompression of the natural gas can take time periods of an hour or more, which is normal depending on the distance to the valve, pipe diameter and the line pressure when the valve was closed.

The conclusion was that the presence of mainline block valves on a gas transmission pipeline do not affect the safety of that pipeline and are installed primarily for maintenance activities.

REVIEW OF PHMSA INCIDENT DATA

The factors that have been included in this review were defined by the factors involved in an incident that affect risk to the public.

- The **first factor** affecting public risk is the proximity of the public to the rupture location. There has no been no control over the proximity of the public to the existing gas transmission pipeline system and the location of a critical defect. However, this is changing with the increased usage of in line inspection tools which can locate critical defects so that they can be remediated before incidents occur. The 2002 Pipeline Safety Act implemented integrity management to reduce the number of incidents in High Consequence Areas (HCA)
- The **second factor** is the number of sources of released gas and this depends on concentration of released gas and whether the fracture runs a long distance separating the two release points or the gas release is from a single point. There is no way to

modify the fracture propagation characteristics of an existing pipeline and therefore this factor is not controllable.

- The **third factor** is whether the gas ignites with the issue being proximity to buildings and the public. Again, whether the gas in a rupture or leak ignites is uncontrollable. From observation 7 percent of the incidents in the whole 2002 to 2009 PHMSA incident data base ignited.
- The **fourth factor** is the length of time required for the line to blowdown or to make the area safe. This is a very subjective factor because the longer it takes for a pipeline to blow down, the greater the noise that the public is exposed to, the greater the exposure in the media and the greater the concern raised about the proximity of gas transmission pipelines to occupied structures. As will be shown, the data generally indicate that injuries and fatalities are associated with the initial release of gas occurring after release and therefore immediate shut down of a line, while desirable, is not possible due to the compressible nature of the natural gas.

Of the four factors identified, only the first and fourth are potentially controllable. The first one is partially controllable by spacing homes a reasonable distance from gas pipelines but this is very costly to enforce because of the numerous occupied structures that are already in close proximity to gas pipelines. Also, it is not economically feasible to enforce setbacks from pipelines such that they cannot be affected by a pipeline failure. The other means of preventing the public from being at risk was implemented in the Pipeline Safety Act of 2002. Pipeline companies are required to periodically assess the integrity of pipelines in High Consequence Areas (HCA) with Integrity Management Programs (IMP). Operators comply by maintaining their pipelines through periodic inspections of pipelines for injurious defects and through damage prevention programs, one-call systems, and right-of-way surveillance. This is expected to reduce the number of incidents but will not eliminate them completely because of the large uncontrolled exposure that exits for pipelines because of their extensive length. Performance data from 2002 to 2009 suggest that there has been an improvement in safety.

The fourth factor is controllable by the type of valve closing mechanisms available, i.e., automatic closing, remote operated, and manual operated. This factor will be examined using data from incidents.

Proximity to the Public

The "proximity to the public" was assessed by examining the number of incidents, injuries, and fatalities that occurred in "high consequence areas," which are defined as pipeline segments that are in regions of high population density where a fire from a pipeline rupture could potentially result in an injury or fatality. Table 1 summarizes the numbers of incidents and incidents per 1000 miles (1600 km) by Class Location, high consequence area, injuries and fatalities for 8 years of data starting with 2002 and including 2009 incidents. This recent data was selected as it represents the impact of the Integrity Management Plans developed after the implementation in Part 192 of Subpart O, Gas Transmission Pipeline Integrity Management.

Table 1 Summary of PHMSA Incident Database Injuries and Fatalities from 2002 through 2009

Class Location[f]	Number of Incidents	Incidents per thousand miles**	Percent of Total Incidents	Injuries, No. (%)	Fatalities, No. (%)
1 – non HCA	333	1.45	70.6	16 (76)	6 (86)
1 – HCA	3		0.6	0	0
2 – non HCA	35	1.17	7.4	3 (14)	1 (14)
2 – HCA	1		0.2	0	0
3 – non HCA*	55	2.52	11.7	2 (10)	0
3 – HCA	30		6.4	0	0
4 – non HCA*	10	12.51	2.1	0	0
4 – HCA	5		1.0	0	0
Totals	**472**			**21**	**7**
non HCA	**433**		**92.0**	**21**	**7**
HCA	**39**		**8.0**	**0**	**0**

* These incidents were not identified as being in HCA areas, a possible error in the database.
** Mileage distribution by Class Location; 1 - 77.9%; 2 - 10.34%; 3 - 11.34%; 4 - 0.4% based on 2008 annual PHMSA data. Total onshore mileage in 2008 is 297,325 miles.

Table 1 indicates that 92 percent of the incidents occurred in non HCA areas with 100 percent of the injuries and fatalities (21 injuries and 7 fatalities) occurring in these areas. There were no injuries or fatalities in the incidents that occurred in HCA's and no injuries or fatalities in Class 4 Locations. The absence of injuries and fatalities in HCA's is due in part to the implementation of Part 192 Subpart O. This is an indication of the effectiveness of in line inspection tools and their ability to detect and identify critical defects as well as the effectiveness of damage-prevention programs, one-call systems, and integrity management planning by operators.

To examine these data in more detail, Figure 1 was prepared to assess the length of time for the area to be made safe (closely related to the time for shut down of gas at the incident site) versus the number of injuries and fatalities in Class 1-3 Locations. The figure shows that all injuries not just ignitions alone occurred in incidents where the "time to make the area safe" extended up to 14 hours after the initial release of gas. Unfortunately, from the available data it is not known when in the 14 hour period the injuries occurred. Based on prior experience, injuries and fatalities occur when the gas is first released as either the gas fires which keep people (public or employees) away from the area. Also, as the gas continues to blowdown it is so noisy that people stay away. (Natural gas is lighter than air and will rise eliminating a concern over suffocation.) This will also be discussed in a future section where individual incidents will be examined. The fatalities all occurred in the first hour after rupture.

[f] Class Location in defined in Title 49 of the Code of Federal Regulations Part 192, in general there are for Class Locations with the higher the Class Location number the higher the population density, Class 1 corresponds to isolated houses and Class 4 corresponds to the urban area of city where multistory buildings exist.

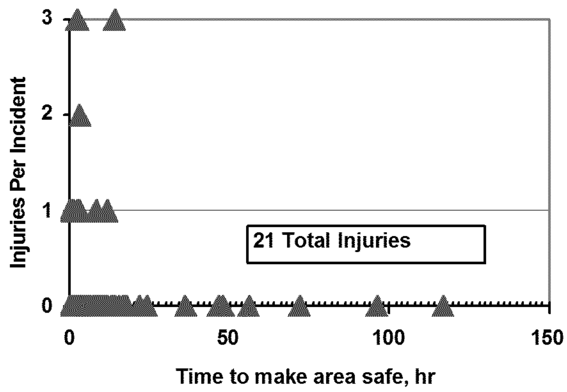

Figure 1a Injuries

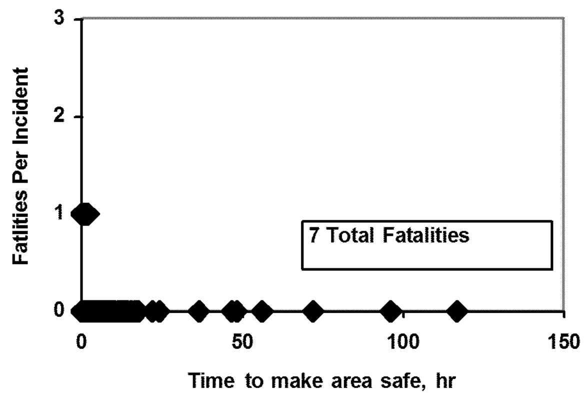

Figure 1b Fatalities

Figure 1 Time to Make Area Safe versus Injuries and Fatalities in Class 1-3 Locations

Concentration of Gas Release

The second factor considered is the concentration of the gas release which is related to the length of the fracture. If a fracture runs along the pipe it forms two separate release points of gas and in the event of initial gas ignition decreases the initial radiation flux depending on the proximity of the two ends of the fracture. The length of the fracture was assessed against the number of injuries and fatalities. The goal of the examination was to evaluate whether remote operating valves would provide additional protection to the public in the form of reduced damage, reduced gas cost or volume of gas lost since natural gas is a green house gas as has been discussed.

Figure 2 presents PHMSA Incident database information comparing the length of fracture to the number of injuries and fatalities that occurred in incidents in Class 1-3 locations[g]. Figure 2a presents the injuries versus total fracture propagation length and it shows that the 21 injuries that occurred were all associated with short ruptures. This condition keeps all the gas concentrated at the origin of the fracture and if there was any construction activity related to the pipeline that contributed to the incident as that is where the individuals would have been located. Figure 2b presenting fatalities versus fracture propagation length presents a similar situation where the fatalities were all associated with no fracture propagation.

[g] This could also be Class 1-4 locations as there were no injuries or fatalities in Class 4 locations.

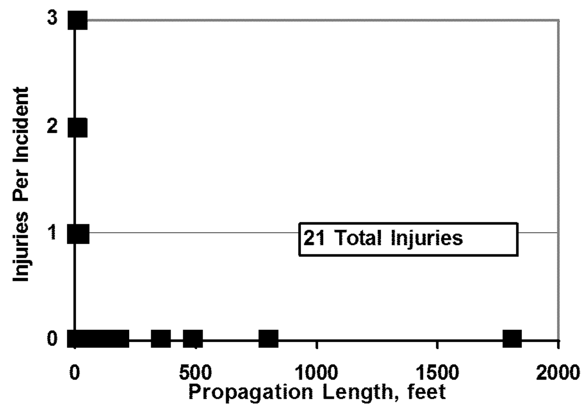

Figure 2a Injuries

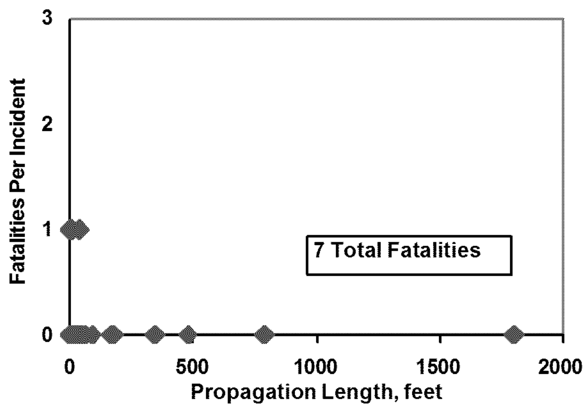

Figure 2b Fatalities

Figure 2 Fracture Propagation Lengths versus Injuries and Fatalities

Figure 3 presents, the total public damage cost, and the lost gas cost versus cost of public damage for Class 1-4 locations. It appears that the property damage cost generally decreases with increasing population density based on total property damage in each class location. This is reflected by the change in the vertical cost scale from 100 million dollars for Class 1 incidents to 125 dollars for the total vertical scale for Class 4 incidents. However in Class 1 and 3 locations there are single incidents that are responsible for 80 percent or more of the total cost in those class locations. These will be discussed.

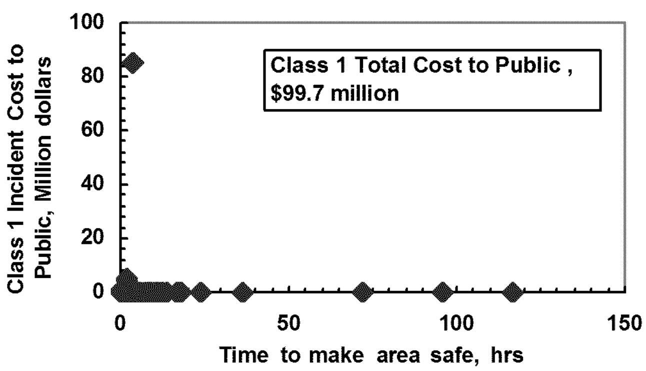

Figure 3a Time versus CL 1 Property Damage

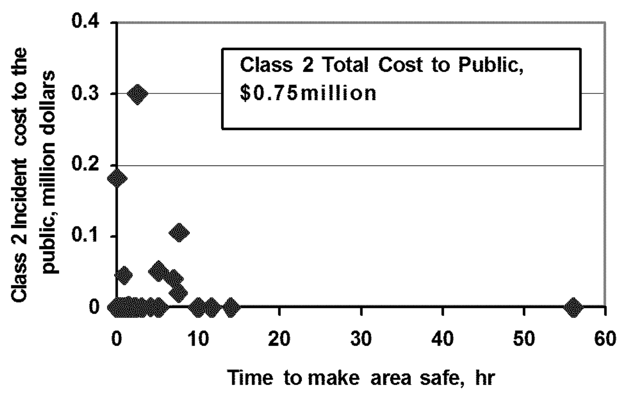

Figure 3b Time Versus CL 2 Property Damage

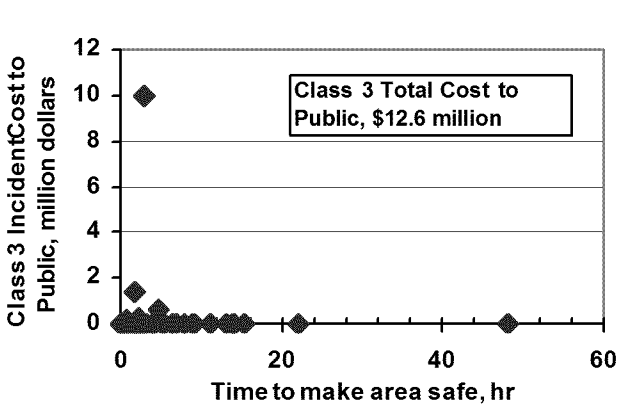

Figure 3c Time versus CL 3 Property Damage

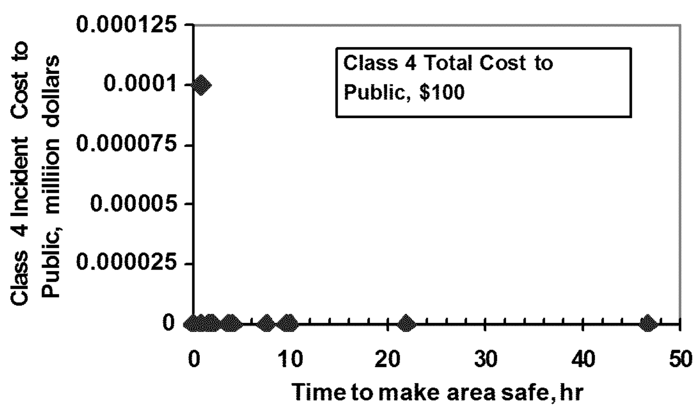

Figure 3d Time versus CL 4 Property Damage

Figure 3 Time to Make Area Safe versus Property Damage by Class Location

Discussion

There were two incidents that stand out in the examination of Figure 3 because of their high cost. These are the $87.5 million dollar property damage in the Class 1 location and the $10 million property damage incident in the Class 3 location.

In the Class 1 location incident that incurred a cost of $87.5 million, the pipe involved was 36 inch (914 mm) diameter by 0.330 inch (8.4 mm) wall thickness flash welded grade X65, produced in 1967. The pipe was coated and cathodically protected. The incident was not located in an HCA. The rupture length was 8 feet (2.4 m) in length and it took 3.5 hours to make the area safe. The gas ignited which prompted the evacuation of 40 people. The incident occurred on a gas pipeline that was supplying gas to a gas fired power plant near the edge of Carthage, Texas. The cause of the incident was a stress corrosion crack that formed in the pipe as a consequence of a corrosive environment being generated on the outside surface of the pipe that created a colony of cracks penetrating into the pipe causing a weak region in the pipe that failed. The public property damage cost was $85 million, 97% of the total cost. The lost gas cost was $1.8 million and the damage to the operator was $0.7 million. The fire damaged the electric power generation station which is assumed to be the reason for most of the property damage cost. With today's technology this type of anomaly could have been detected prior to failure if the correct type of inspection tool had been used. From the information available, it appears that remote operating valves coupled with an accurate SCADA system for rupture detection may have significantly reduced the damage to the generating plant depending on the distance of the valves from the rupture.

The other question that arises from this incident is whether the valve placement could have been improved. A call to the operating company failed to obtain any information on the cause of the incident or the location of the valves. It is assumed that the existing valve spacing was on the order of 20 miles (32 km) which would partially explain the high lost-gas cost but the cost associated with the power plant damage could not be verified.

In the Class 3 location incident that incurred with a total property damage cost of $10 million dollars, the pipe involved was 16 inch (406 mm) diameter by 0.24 inch (610 mm) grade X60 electric resistance welded pipe produced in 1989 by American Steel Pipe. This incident was located in an HCA. The rupture length was 89 feet (27 m) and it took 3 hours to make the area safe. The pipeline was classed as a gathering line as it was a supply line for a gas processing facility. The gas processing facility was damaged in the fire but not completely destroyed as it was back in operation approximately a month after the incident. Fifty people were evacuated as a safety precaution during the incident. The total incident cost was 10.0 million dollars. The public property damage cost was $9.96 million, the lost gas cost was $0.020 million and the cost of damage to the operator was $0.020 million. In a Class 3 location, the valve spacing has to be 8 miles or less and this probably contributed to the proportionally lower lost gas cost in this incident compared to the previous one in a Class 1 location. It appears that since the gas ignited in both incidents this substantially increased the damage and thus total cost.

The options to reduce the damage in the incidents would be to shorten the valve spacing which would have helped in the Class 1 location incident but probably would not have been effective in the Class 3 location incident. Remote operated valves may have reduced the time to make the area safe in both Class location incidents because of the relatively long times required for the area to be made safe.

The "time to make the area safe" was examined further by exploring each Class location to examine the trends in the PHMSA data for time to make the area safe versus the total incident cost to evaluate whether there are other incidents that can be examined to learn more about what can be done to provide increased safety to the public or reduce the consequences of an incident. Figure 4 presents time to make an area safe versus total incident cost for the four Class locations.

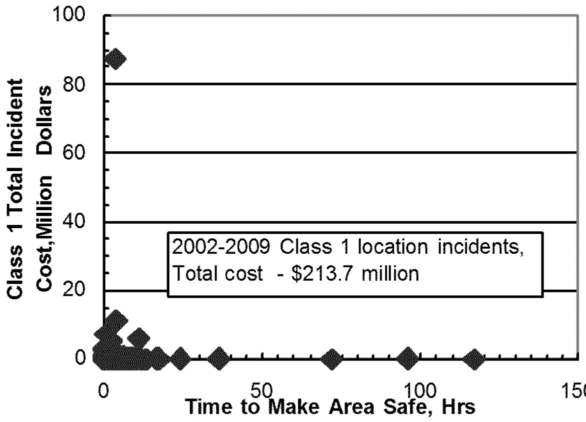

Figure 4a Class 1 Location

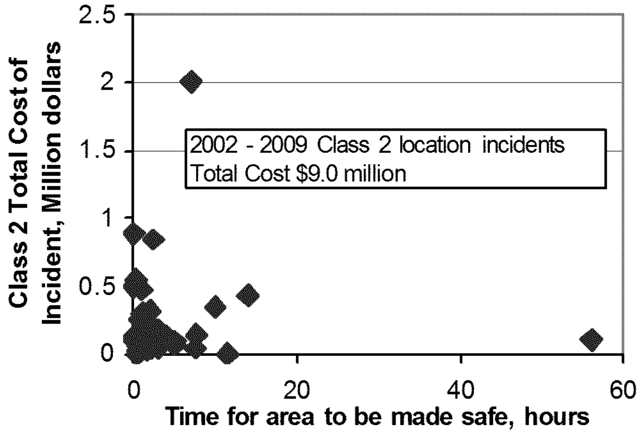

Figure 4b Class 2 Location

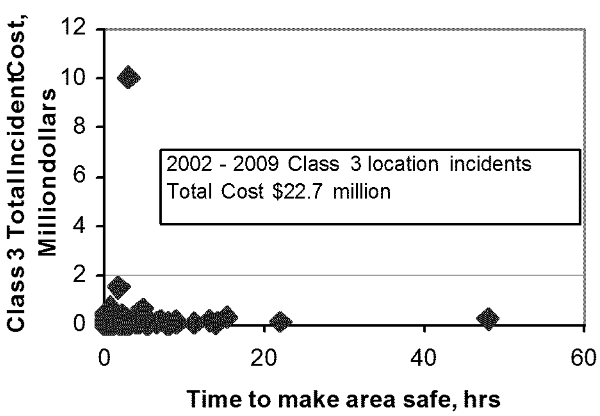

Figure 4c Class 3 Location

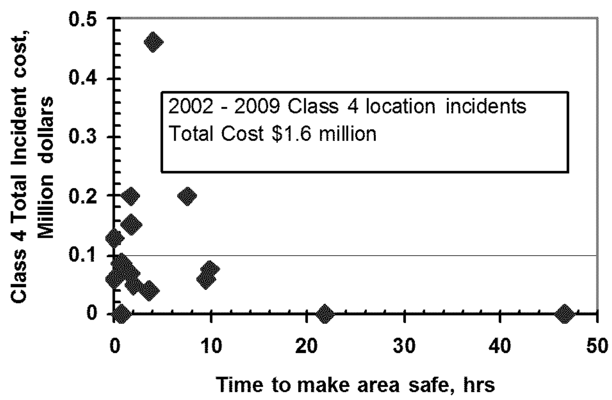

Figure 4d Class 4 Location

Figure 4 Time to Make Area Safe versus Total Cost by Class Location

Examining the data in Figure 4, there were eleven incidents in Class 1 that incurred costs over 2 million dollars. The key factors of these incidents are summarized in Table 2. The table indicates that there was only 1 fatality and no injuries in the 11 incidents and that was associated with Incident 2 in the table. The time to make the area safe in Incident 2 was reported as 0 time which is questionable as it is very difficult to achieve. There was only one incident where the gas ignited and that was incident 11 with the 87.5 million dollar total cost. The incident with the longest time to make the area safe was incident 8 and that incident had a lost gas cost that was 98 percent of the total 6.22 million dollar cost but the public damage cost was only $3000. Obviously in this incident, if the gas could have been shut off sooner then the lost gas could have been reduced but this did not affect public safety. There are two incidents (6 and 7) with 5.4 and 5.7 million dollar costs where the public damage costs were a high percentage of the total cost. In both of these incidents, the time to make the area safe was 2 hours and could have been cut in half by more rapid closure of valves, i.e., remote operating

Table 2 Class 1 Incidents With Total Costs $2.5 to $87.5 million

Incident No.	1	2	3	4	5	6	7	8	9	10	11
Date	**4/29/08**	**12/14/07**	**3/15/02**	**2/20/03**	**11/2/03**	**9/14/08**	**5/20/03**	**2/5/07**	**4/12/08**	**8/3/07**	**5/3/05**
Total Cost, million $	2.5	3.05	3.1	3.26	3.3	5.42	5.74	6.22	7.45	11.34	87.5
Public Prop. Damage Cost, million	0	0.75	0.4	0	0.15	4.32	5.17	0.003	0	0.34	85
Gas Cost, million $	0.016	0.2	0.46	0	0.84	0.1	0.09	6.12	4.5	0	1.8
Operator Damage Cost, milllion	2.5	2.1	2.25	3.26	2.32	1.0	0.48	0.1	7.0	11.0	0.7
Fatalities	0	1	0	0	0	0	0	0	0	0	0
Injuries	0	0	0	0	0	0	0	0	0	0	0
Location, state	LA	LA	MI	MO	KY	VA	TX	KS	LA	LA	TX
Ignition	No	no	na	no	no	no	no	no	no	no	yes
Under ground/water	under water	under ground	under ground	under water	under ground	under ground	under ground	under ground	under water	under water	under ground
Time to make area safe, hr	0.5	0	1.25	2	3.3	2.02	2	11	0.5	4	3.5
Rupture length, ft	Na	36	7	na	2	30	na	na	na	10	8
HCA/Non	non	non	non	non	non	non	non	non	non	non	non
Pipe, D x t, inch (mm); Grade	16 x 0.5 (406x12.7) X52	30 x 0.38 (762x9.5)	36 x 0.38 (914x9.5) X65	24 x 0.50 (610x12.7) X37	30 x 0.38 (762x9.5) X52	30 x 0.34 (762x8.6) X52	30 x 0.31 (762x7.8) X65	26 x 0.31 (660x7.8) X52	12.8 x 0.5 (324x12.7) Grd B	20x0.34 (508x8.6) X52	36x0.33 (914x8.4) X65
Pipe Install date	1954	1954	1968	1943	1957	1955	1975	1948	1958	1959	1967
Cause	na	corrosion	SCC*	corrosion	mfg defect	corrosion	corrosion	girth weld	3rd party damage	seam weld	na

* SCC, stress corrosion cracking

valves, which probably would not have reduced the damage to public property but we do not have sufficient data to verify this. Overall, rapid valve closing with an automatic closing or remote closing valve would not have reduced the public property damage cost in three of the incidents. In the one incident with a fatality, the area was indicated as safe in zero time so the conclusion has to be that the fatality occurred at the instant of gas release.

A remote closing valve can take 30 or more minutes before the line with a rupture is identified, approvals received and the closure initiated. Automatic valves require sufficient pressure differential to effect closure, and manual valves require someone to drive out and turn the wheel. None are instantaneous but the automatic might be the quickest depending how far away it is and if it closes as designed. Thus, neither damage nor risk is correlated to the time to make an area safe.

REVIEW OF NATIONAL TRANSPORTATION SAFETY BOARD (NTSB) SERIOUS GAS TRANSMISSION INCIDENTS

The prior review of the PHMSA incident database indicated that overall the industry is generally doing a good job of protecting the public. There are occasionally serious incidents that have occurred and investigated by the NTSB. The goal of this section is to review the serious incidents to determine if there are actions identified in these incidents that could further improve pipeline safety using the block valves on gas transmission pipelines. It should also be kept in mind that these incidents cover a 41 year time period and much has been learned during this time and new tools developed for the inspection of defects.

All of the 110 NTSB reports on pipelines covering 1969 to 2009 were reviewed to determine which ones apply to gas transmission pipeline incidents. Thirteen incidents pertaining to natural gas transmission pipelines on shore were selected and examined. Of the remaining 97 NTSB reports,

- 34 pertained to liquid pipelines,
- 58 reports pertained to gas distribution incidents involving low pressure lines in cities, and
- 6 reports pertained one each to a storage tank, compressor station, plant, gas gathering line, pipeline snagged by anchor in 300 feet (92 m) of water and a boat hitting an offshore pipeline.

The 13 reports on gas transmission pipelines were examined in detail on whether closure of transmission line block valves would have affected the consequences to the public. A brief synopsis of each report will be presented with the observations identified followed by an assessment of all the incidents.

1. Mobil Oil Corp, High Pressure Natural Gas Incident, Houston, Texas, September 9, 1969[9]

The incident involved a 1941/42 14 inch (356 mm) diameter pipe with a 0.250 inch (6.4 mm) wall thickness Grade B API ERW pipe. A section of the pipeline was relocated because of the installation of a canal and then tested with gas to a pressure of 780 psi (5.4 MPa) when rupture occurred. The maximum allowable operating pressure for this line was 765 psi (5.3 MPa). The line ruptured at M.P. 110.3 at 3:40 pm in the low frequency ERW seam and approximately 8 to 10 minutes later the gas caught fire creating an overpressure wave and at about the same time 5 houses exploded after having filled with natural gas. The rupture was located in the vicinity of a housing subdivision with the nearest house being 24 feet (7.3 m) away. The valves upstream

(M.P. 101.7) and down stream (M.P. 112) were 8.6 and 1.7 miles (13.8 and 2.7 km) away respectively, a valve spacing of 10.3 miles (16.5 km). The manual closing valves were closed 1 hr and 13 minutes and 1 hr and 15 minutes after the rupture. The fire continued to burn for an additional 5 hours. Thirteen houses were completely destroyed and 106 were damaged. Nine persons were injured, two seriously.

The cause was associated with the elevated pressure introduced into the line because of the malfunction of a pressure regulator allowing the pressure to increase to the highest pressure that the line had experienced.

The gas exited the line for a little over an hour before the valves were closed. Thirteen houses ranging from 24 to 250 feet (7.3 to 76.2 m) from the pipeline burned and 106 were damaged.

Observations:

- If the valves could have been closed at the time of rupture, i.e., automatic closing valves, the damage to the homes probably would have been reduced because the gas burned for 1.5 hours in the incident and once the valves were shut the gas fire was out in about 15 minutes. The fire intensity was noted as reduced after the valves were closed but there would still have been significant heat radiation from the fire to damage homes while the gas was burning.
- The five houses that ruptured were not affected by the valve closing times and were simply in too close a proximity to prevent filling with gas which upon ignition exploded the homes.
- If the valves had closed immediately, the injuries to people and damage to houses would probably not have been reduced but there are no details on the cause of the injuries that allows this speculation to be confirmed.
- The best solution is to make sure the rupture does not occur. Congress has implemented integrity management for all HCA's in the 2002 Pipeline Safety Act. (Note this capability was not well developed at the time of this incident.) (The NTSB recommended that DOT conduct a study on rapid shutdown of failed gas pipelines.)

2. Michigan-Wisconsin Pipe Line Company, Monroe, Louisiana, March 2, 1974[10]

A 30 inch (762 mm) diameter by 0.438 inch (11.1 mm) wall thickness API Grade X52 flash weld pipe produced in 1956 failed at 11:40 am at a girth weld inside a casing under a highway. The released gas ruptured the casing producing a trench 100 feet (30.5 m) long which severed the road above the casing. The pressure at the time of the accident was 797 psig (5.4 MPa). Main line block valve No. 10, located 1 mile (1.6 km) upstream from the failure was an automatic closing valve and it closed automatically. Main line block valve No. 11 located 17.1 miles (27.4 km) downstream from the failure was also an automatic closing valve set to close on a sustained pressure drop of 20 psi (138 kPa) per minute but failed to close. Valve 11 was closed manually 85 minutes after the first release of gas. Previously, the valves had been set to close on a pressure drop of 12 psi (83 kPa) per minute but this setting caused a number of inadvertent closings and the pressure drop setting was changed to 20 psi (138 kPa) per minute. The accident burned 10 acres of forest and sterilized the soil for 700 feet (0.2 km) south along the right-of-way. There were no injuries or fatalities associated with the incident.

The valves had operated correctly in a previous incident involving another girth weld failure 14 years earlier (1960). Another incident on this line segment 3 years later (1963) involving a small corrosion pit from interference current did not have a sufficient pressure drop for the valves to operate.

Observations:

- This incident illustrates the difficulty of getting automatic closing valves to close during a failure. The valve 1 mile away experienced a pressure drop in excess of the valve closure setting of a pressure drop of 20 psi (138 kPa) per minute and closed as desired. The valve 17.1 miles (27.4 km) away did not experience a pressure drop of 20 psi (138 kPa) per minute because of the distance from the rupture and had to be closed manually.
- The pressure drop setting was used for these valves because it is not sensitive to normal pressure fluctuations and yet a 12 psi (83 kPa) drop setting was too small and triggered a number of inadvertent valve closings.
- Since there were no injuries or fatalities in this incident the valve spacing and closing times did not contribute to the consequences of the incident.

3. Transcontinental Gas Pipe Line Corp 30 inch Gas Transmission Pipeline Failure, Near Bealeton , Virginia, June 9, 1974[11]

A 30 inch (762 mm) diameter by 0.312 inch (7.9 mm) wall thickness X52 DSAW (double submerged arc welded) pipe produced in 1957 failed at a hard spot in the pipe wall at 10:05 am due to hydrogen stress cracking. The released gas ignited and burned for 4 hours and 25 minutes. There were no injuries or fatalities in the remote location where the incident occurred. The automatic closing valve 10.6 miles (17 km) downstream failed to close as well as the automatic closing valve 4.7 miles (7.5 km) upstream. Both were set to close on a 28-30 psi (193-207 kPa) sustained pressure drop per minute. (This value had been increased from the initial setting of 20 psi (138 kPa) pressure drop per minute due to inadvertent closings. The addition of a loop line and open cross-over valves between the three lines made the higher pressure drop setting for activation of the automatic valve inappropriate.)

The compressor also had a rupture alarm system which failed to operate and identify which line had ruptured. Transco had 3 looped lines in this segment and the ruptured line could not be identified. A maintenance crew was dispatched to manually close the A Line main line valves on either side of the rupture and this occurred 1 hour and 10 minutes after the rupture. However, when closed it was noted that the B Line was still losing pressure and these main line valves were manually closed 2 hours and 10 minutes after the rupture, The gas burned for a total of 4 hours and 25 minutes.

Observations

- The automatic closing valves on both sides of the rupture failed to close because the pressure drop setting was too high to actuate the valves. This was due to the relatively large pressure drop setting on the valves, the open cross-over valves, the parallel lines at the rupture site and the distance from the rupture.
- A second complicating issue in closing the valves was the difficulty in identifying the line with the rupture when 3 parallel lines existed in the same right-of-way. (It was noted that the compressor station personnel could see the fire but could not accurately identify which line had ruptured.)

4.Southern Union Gas Company Pipeline Failure near Farmington, New Mexico, March 15, 1974[12]

A rupture occurred in a 12 inch (305 mm) diameter by 0.250 inch (6.4 mm) wall thickness flash welded pipe[8] produced in 1948. The rupture occurred at 3:45 am having initiated in a region of

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[8] Pipe grade was not identified.

selective corrosion in the flash weld. Three people died in the incident because of driving into the gas cloud[9], probably igniting it and a 300 foot (91.4 m) diameter area was burned. The manual mainline block valve 4.1 miles (6.6 km) south was closed 1 hour after the rupture started. The manual mainline block valve 4.8 miles (7.7 km) north was closed 1 hour and 15 minutes after the rupture started. No automatic closing valves existed on this line. The fire died out 2 hours and 31 minutes after the rupture occurred.

This pipeline consists of 3 parallel lines in the section of the incident. The lines are 10, 12, and 20 inches (254, 305. and 508 mm) in diameter. The original line was 10 inches (254 mm) laid in 1929-1930, bare and mechanically coupled. In the twelve years prior to the failure there had been 130 corrosion leaks on the 12 inch (305 mm) diameter line but no ruptures occurred.

Observations

- The deaths associated with this rupture could not have been prevented by a change in valve spacing or automatic valves or remotely operated valves because the deaths occurred shortly after the gas ignition occurred.
- This incident occurred in what appears to have been a Class 1 location, but the valve spacing was only 8 miles (13 km) which is what is commonly used currently in a Class 3 location and yet this valve spacing did not affect the outcome of the incident.
- The way to control incidents such as this is through integrity management plans that inspect, identify and locate anomalies in the pipeline to eliminate the occurrence of the incident.

5. United Gas Pipe Line Company, 20 inch Pipeline Rupture and Fire, Cartwright, Louisiana, August 9, 1976[13]

A rupture occurred at 1:05 pm in a 20 inch (508 mm) diameter by 0.250 inch (6.4 mm) wall thickness API grade X46 Youngstown Sheet and Tube electric resistance welded (ERW) pipe produced in 1949. The rupture initiated when a road grader contacted the pipe creating a dent and gouge that ruptured. The grader operator ran from the grader leaving the engine running which probably ignited the gas resulting in burns to the operator but he survived. The damage and fatalities occurred minutes after the rupture. Four people suffocated in a house approximately 90 feet (27.4 m) from the pipeline rupture and 2 people were killed in trying to escape from their burning mobile home approximately 160 feet (48.8 m) from the rupture. The house and mobile home were in line with the pipeline jetting gas. Another house approximately 400 feet (122 m) and roughly perpendicular from the pipeline rupture was burned but no injuries or fatalities occurred.

The failure occurred at approximately M.P.113.5 and mainline manual block valves were located at M.P.107.68 (5.8 miles) (9.3 km) and M.P.118.96 (5.4 miles) (8.6 km). The rupture occurred at 1:05 pm and the valve at M.P.118.96 was closed at 1:45 pm 40 minutes after the rupture. The valve at M.P.107.68 was closed at 2:05 pm 1 hour after the rupture. No automatic closing or remote closing valves existed in this segment of the line.

At the rupture location, a 20 inch (508 mm) and a 24 inch (1219 mm) diameter pipeline existed. United did not have detection equipment to identify which line had ruptured. The instructions were to close the 20 inch (508 mm) line first and then the valves on the 24 inch (1219 mm) line.

[9] The NTSB report suggested that the truck drove into the gas cloud from the rupture. It is believed that early in the morning when this incident occurred the gas was not visible and the driver drove his truck into the gas which stopped the truck due to lack of oxygen. This allowed one person to run a short distance from the truck but the other two people were in the truck after the incident.

The 24 inch (1219 mm) line valves were finally closed 3 hours and 15 minutes and 3 hours and 25 minutes after the rupture.

Observations

- The burns to the operator occurred during the first minute of the rupture when the gas ignited.
- The fatalities would not have been prevented if automatic closing valves had been present because the fire would not have been extinguished with the closing of the valves. It would still have burned for a significant period of time as the gas in the pipeline depressurized.
- No capability existed to identify which of the two lines had ruptured. This again identifies the problem of which line ruptured when parallel lines exist in a right-of-way.

6. Northern Natural Gas Company, Pipeline Puncture, Explosion, and Fire, Hudson, Iowa, November 4, 1982[14]

A rupture occurred at 2:15 pm on a 20 inch (508 mm) diameter by 0.281 inch (7.1 mm) wall thickness API 5LX -52 pipeline during the installation of drainage tile in a farmer's field in 1982. A Northern Natural Gas Company person was monitoring the gas line crossing by the tile plow involving crossing 20 and 26 inch (508 and 660 mm) diameter lines in the morning. This crossing involved pipe depths of 8 feet (2.4 m) deep following which the drainage crew indicated they would not be crossing the gas lines again and Northern Natural representative left the field. In the early afternoon, the contractor changed his plans and crossed the 20 inch (508 mm) line with a tile plow where the pipeline was only 36 inches (914 mm) deep which punctured the pipe releasing gas that immediately caught fire at 2:25 pm fatally injuring the drainage installation crew of 3 and 2 soil conservationists who where watching the installation.

The manual main line block valves (14.4 miles [23 km] apart) were closed at 2:57 pm (42 minutes after rupture) and 3:20pm (65 minutes after rupture) followed by final closure of the cross over valve from the 26 inch (660 mm) to the 20 inch (508 mm) at approximately 4:00 pm (105 minutes after rupture).

Observations

- The fatalities occurred immediately upon gas release and ignition.
- The valves were closed quickly. Even if the valves had been automatic closing they would not have changed the outcome of the incident because the fatalities occurred at the time of gas release and ignition.
- The valve spacing of 14.4 miles (23 km) was less than required in a Class 1 location.

7. Mississippi River Transmission Corp. Natural Gas Flash Fire, Pine Bluff, Arkansas, October 1, 1982 [15]

During modification of a 22 inch (559 mm) gas pipeline, a 1/4 inch (6.4 mm) steel plate was welded to close off the line just downstream of a main line valve. The block valve leaked allowing the pressure to build up on the steel plate which caused it to blow off and the gas ignited engulfing the workers. No fatalities occurred but seven injuries resulted requiring hospitalization.

Observations:

- Care was not exercised in checking the leakage through the valve which caused the release of gas.

- The immediate ignition of the released gas caused the injuries. Neither the spacing of the valves nor their type of closure could have mitigated the consequences as the valve was already closed but leaking. This is another instance indicating immediate injuries at the instant of gas release in a gas pipeline failure.

8 & 9. Texas Eastern Transmission Corp. Natural Gas Pipeline Ruptures and Fires at Beaumont, Kentucky on April 27, 1985 and Lancaster, Kentucky on February 21, 1986.[16]
At approximately 9:10 am on April 27, 1985 a 30 inch (762 mm) diameter by 0.375 inch (9.5 mm) wall thickness X52 pipeline constructed in 1952 ruptured at a pressure of 990 psig (6.8 MPa) in a casing under Kentucky State Highway 90 that was shorted to the pipe due to atmospheric corrosion and immediately caught fire. The fire injured three individuals attempting to escape from their home south of the rupture and killed 5 individuals in their home north of the rupture. The block valve at the compressor station was closed at 9:23 am and the block valve 18 miles (29 km) north of the compressor station was closed at 10:31 am. Following the incident, Texas Eastern in-line-inspected (ILI) their pipelines in Kentucky and changed a total of 35 pipe lengths.

At approximately 2:05 am on February 21, 1986, a 30 inch (762 mm) diameter by 0.375 inch (9.5 mm) wall thickness X52 pipeline constructed in 1957 near Lancaster, Kentucky ruptured at a pressure of 987 psig (6.8 MPa) due to galvanic corrosion and immediately caught fire. The fire injured 3 individuals and required evacuation of 77 additional individuals. The block valve 7 miles (11.2 km) upstream was closed at 2:15 am and the block valve 11 miles (17.6 km) downstream was closed at 2:46 am. The area of corrosion that failed had been identified in the previous ILI but the severity of the corrosion could not be verified due to the pipeline resting on a large rock ledge. The pipe to soil potential measurements at both rupture sites were all above the -0.85v criteria indicating that the corrosion was being controlled.

Observations:
- The ignition of the gas in both incidents occurred at the time of rupture.
- The injuries and fatalities in both incidents occurred at the time of the release of gas.
- The valves in both incidents were closed in an expeditious manner but the injuries and fatalities would not have been prevented if the valves had closed at the instant of gas release due to the time required for the 987 psig (68 atmospheres) natural gas to discharge from the pipelines.

10. Texas Eastern Transmission Corp. Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994 [17]
At 1:15 am a 36 inch (941 mm) by 0.675 inch (17.1 mm) wall thickness X52 pipeline constructed in 1961 ruptured from mechanical damage. The mechanical damage occurred on land owned by an asphalt company. After the rupture excavation revealed that the pipe which had originally been buried 7 feet (2 m) deep was now buried 12 feet (3.7 m) deep and further excavation revealed a number of items buried near the line including a stolen car, file cabinet, and drums of hazardous liquids. The gas ignited 1 to 2 minutes after the rupture which caused heat radiation to ignite apartment buildings 300 feet (91.4 m) away. Fortunately, rapid evacuation prevented fatalities from occurring to the residents. There were 100 minor injuries and 2 serious injuries.

Texas Eastern quickly dispatched staff to close the manual block valves that were located 0.4 mile (0.64 km) south (M.P.29.58) and 5 miles (8 km) north (M.P.34.98). The rupture occurred at M.P. 29.96. Valve 20-88 at M.P. 34.98 was closed at 1:35 am twenty minutes after the rupture. Valve 20-83 at M.P. 29.58 could not be closed because the pressure was not adequate to operate the valve actuator due to it being so close to the rupture. The staff tried to close it manually but were not successful because of the high differential pressure. They then closed the manual main line valve 20-77 at M.P. 24.20 at 2:00 am 45 minutes after the rupture.

Observations

- This is a rupture where automatic closing valves, if they had worked, might have reduced the consequences of the ignition from the rupture. The valves in this situation were closer than required by Part 192 being 5.4 miles (8.6 km) apart when Part 192 required an 8 mile (12.8 km) spacing. The reduction in damage with automatic closing valves would have been minimal because 5 miles (8 km) of gas in a 36 inch (914 mm) diameter line would have taken time to blow down and there still would have been heat radiation for a period of time that would have damaged the nearby apartment buildings.
- Prevention of the incident is the only way to protect the public in high population areas such as existed in this case.
- Another observation is that pipelines operated in high consequence areas such as Edison, NJ, need to have integrity management plans and damage prevention programs developed and implemented to assure that the line will not experience a rupture in a populated area. (With the implementation of Sub Part O in Part 192 in 2003, these types of accidents will be reduced.)

11. Dredging of Tiger Pass, Louisiana, October 23, 1996 [18]

At 4:50 am the dredge, Dave Blackburn, dropped a stern spud (large steel shaft used as an anchor and stern pivot point) which struck and ruptured a 12 inch (305 mm) diameter Tennessee Gas Transmission natural gas pipeline. The gas ignited immediately destroying the dredge and tug. All 28 members of the dredge and tug escaped with only one injury. The pipeline had been mis-located by approximately 90 feet contributing to the incident.

The downstream check valve approximately 2 miles (3.2 km) from the rupture closed automatically. Company personnel closed a manual valve on an offshore platform 9 miles (14.4 km) upstream about 1 hour and 10 minutes after the rupture. Also, a manual main line valve downstream adjacent to the check valve was closed 2 hours and 35 minutes after the rupture to insure that the rupture was completely closed off from the gas supply on both sides. The fire was out 2 hours and 10 minutes after the rupture occurred.

Observations

- All of the destruction and threat to the dredge and tug crew occurred at the instant the gas reached the water surface. Changing valve spacing or mode of closure would not have protected the crews of the dredge and tug as the threat to them occurred immediately.
- The check valve reduced the volume of gas at the rupture site. Check valves are not as tight as a main line block valve but reduce the amount of gas available to feed a fire. The fire had extinguished before the main line block valve adjacent to the check valve was closed.
- The platform valve was closed in 1 hour and 10 minutes but this still allowed 9 miles of gas in the line to feed the fire before it went out in 2 hours and 10 minutes. If the platform valve had been closed immediately, it still would have allowed the fire to burn for at least another hour which would probably not have changed the damage to the dredge and tug.

12. Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000 [19]
At 5:26 am a 30 inch (762 mm) diameter by 0.335 inch (8.5 mm) wall thickness API X52 El Paso Natural Gas pipeline laid in 1950 ruptured adjacent to the Pecos River. The released gas ignited and burned for 55 minutes. Twelve persons camping under the bridge that supported the pipelines across the river were killed. The area of the campsite was identified as a "private right-of-way" marked by signs and a wire rope enclosure. The cause of the rupture was internal corrosion in the pipe.

As in other pipeline incidents the operator could not determine which of the four pipelines (16 inch (406 mm) [line 3191], 26 inch (660 mm) [line 1100], and two 30 inch (762 mm) diameter lines [lines 1103 and 1110]) in the right-of-way had failed. El Paso personnel closed all four main line block valves at the compressor station 0.85 mile (1.4 km) downstream of the rupture. They then proceeded to the upstream valves located 0.25 mile (0.4 km) upstream and closed the main line valve on line 1100 but there was no change in the fire intensity. They therefore closed the main line valve on line 1103 also 0.25 miles (0.4 km) upstream and the intensity of the fire decreased significantly. They then closed the by-pass valve on the pig receiver and the fire stopped at 6:21 am 55 minutes after it started.

Observations

- This is another situation with 4 multiple pipelines in the right-of-way where the ruptured line could not be quickly identified. In this instance, the rupture line identification did not appear to have affected the outcome of the incident because the valves on all lines were closed at the station. One valve upstream was closed before the ruptured line valve was closed. Even if all valves had been closed upstream, this would not have changed the consequences of the rupture.
- The fatalities of the trespassing campers would not have been affected by changing the spacing of the valves (which was already very short approximately 1.25 miles (2 km) between them).
- If automatic closing valves had been present, it is possible that the fire could have been extinguished much sooner possibly eliminating the fatalities. However, as close as these valves were to the rupture their operation may have been doubtful if they were using gas pressure to power the operator on the valve as the gas pressure would have decayed.

13. NTSB investigation of Florida Gas Transmission Rupture alongside Florida Turnpike, May 4, 2009. [20]
The factual report for this incident has been issued. The rupture investigation is ongoing at this time but is included herein to document that more recently installed automatic closing main line valves can function as they are designed. This rupture involved a failure in an 18 inch (457 mm) by 0.250 inch (6.4 mm) X52 low frequency ERW pipe laid in 1959. The rupture occurred because of cracks that developed in the ERW seam and base metal.

The pipeline was located parallel to the Florida Turnpike and separated by approximately 25 feet (7.6 m) from the traffic lanes. The initial release of gas and debris caused two vehicles to roll over with no injuries or fatalities.

The main line valve upstream was an automatic closing valve installed in 2004 as part of a replacement program and was located approximately 4 miles (6.4 km) away and downstream was a manual main line valve that was approximately 16 miles (25.6 km) away. The automatic valve closed immediately after the rupture occurred. The down stream valve was closed manually and blew down for several hours before all the gas was exhausted from the pipeline. Fortunately, the gas did not ignite which reduced the consequences of this incident.

NTSB Conclusions

The review of the 13 specific incidents on gas transmission pipelines revealed a number of significant pieces of data. These are summarized in the following:

- All 13 incidents examined by the NTSB were considered serious incidents otherwise they would not have been investigated.
- Twelve of the thirteen involved ignition of the gas which caused more damage, injuries and fatalities then if the gas had not ignited. Whether the gas ignites or not is a function of whether an ignition source is available. When the gas ignites, the heat radiation causes the injuries, fatalities and public property damage. The length of time required to close the valves does not determine the amount of damage because even if valves could be closed upstream and downstream immediately the length of time required for the gas to decompress from the pipe line provided sufficient time for major damage to occur.
- The valve spacing in the incidents ranged from 1.1 miles to 18.1 miles (1.8 to 29 km). Ironically, the greatest number of fatalities was associated with the shortest valve spacing of 1.1 miles (1.8 km) as a result of the specific situation in the incident.
- There were a total of 129 injuries in five incidents (102 in one incident with two serious). There were a total of 27 deaths in 5 of the 13 incidents.
- In all of the incidents with injuries and fatalities they happened either immediately or shortly after the gas ignited. Thus, automatic closing valves or short valve spacing would not have improved the safety to the public from incidents on these gas transmission pipelines.
- In three of the incidents there were 5 automatic closing valves associated with the incidents. Only two of these valves closed in the incident. Admittedly two of the incidents occurred in 1969 and 1974 and it is highly probable that the sensing devices have been improved since that time reflected in the last incident, which occurred in 2009 and the valve closed as desired. However, in these incidents with automatic closing valves even if the valves had closed automatically, the consequences would not have changed.
- One of the problems detected in the review was identifying which pipeline had failed when parallel lines exist. It appears that an improved methodology or device to identify the failed line is needed by the industry.

BLOWDOWN TIME RELATED TO VALVE SPACING

Further evaluation of the effect of block valve spacing and valve operator type involved making theoretical calculations of the times required for blowdown of a pipeline assuming various valve spacing and operator type. These calculations were made by Dave Warman of Kiefner and Associates to develop an improved understanding of the factors involved in the blowdown of a pipeline in an incident.

Figure 5 presents a summary of the blowdown calculations performed for a 36 inch (914 mm) diameter by 0.385 inch (9 mm) wall thickness X65 pipe pressured to 1000 psig (6.9 MPa). The theoretical calculated times are the best that can be achieved as in a real situation the times maybe longer due to 1) difficulty in identifying which line has failed when parallel lines are present as they can affect the time for manual valve and remote operated valve closure, 2) whether the automatic closure valve is set to close under the conditions involved in a specific incident, i.e., the rate of pressure drop or the total pressure drop present in a given incident, and 3) in the case of manual valves an employee must physically go to the valve site and occasionally employees are prevented from quickly reaching the valve site because of the public trying to witness the event.

Figure 5 presents blowdown curves for a 40 mile pipeline with valves spaced at 1.4 , 2.6, 4.2, 7.5, 10 and 20 miles (2.2, 4.2, 6.7, 12, 16, 32 km) . The times shown are the most optimistic times that are achievable. Three types of valve closing operators were examined, manual, remote operated and automatic.

- For the manual operation the assumption was that it would take
    a. 30 minutes to identify the failed line and obtain approvals,
    b. 20 minutes for an employee to reach the valve site and
    c. 25 minutes to close the valve.
- For the remote operating valve it was assumed that the valve would be closed within
    a. 30 minutes of the rupture which is primarily the time to identify the failed line and obtain approval for closure.
- For the automatic closing valve, it was assumed that that the valve would close upon a pressure drop of 400 psig with 30 sec required for the valve to close.

The manual valve curve indicates that it will take times between 75 and about 130 minutes to close manual valves under the stated assumptions and valve spacing. The remote closing valves were predicted to take from 30 to 85 minutes to close under the stated assumptions and valve spacing. The automatic closing valves were predicted to close in 2 to about 70 minutes under the stated assumptions and valve spacing. The minimum and maximum times correspond to a valve located 1.4 miles and 20 miles (2.2 to 32 km) respectively from the rupture site.

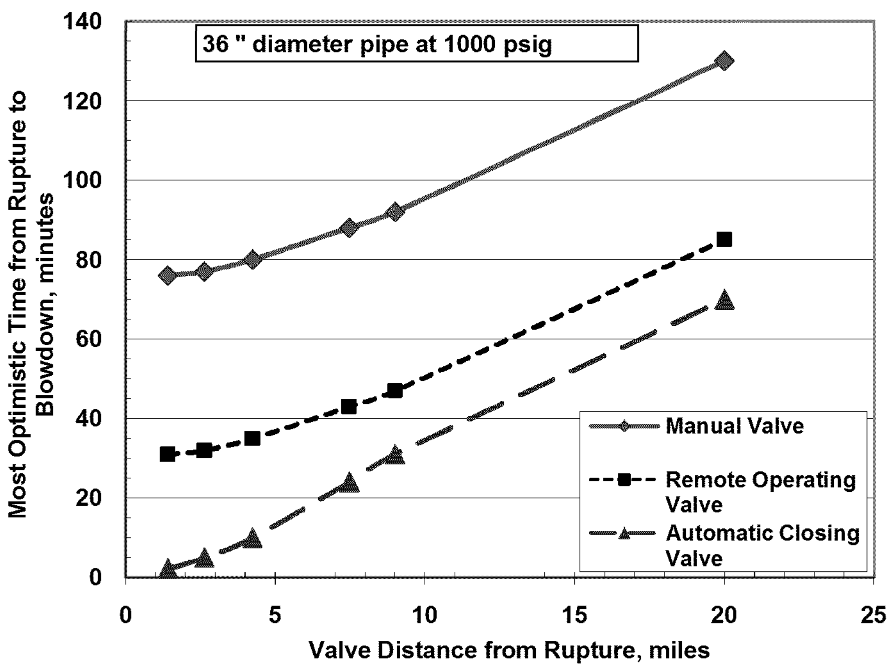

Figure 5 Optimistic Blowdown Times for a 36 inch (914 mm) Diameter 1000 psig Pipeline with Valves Spaced from 1.4 to 20 miles (2.2 to 32 km) from the Rupture

None of the three valve closing scenarios examined would prevent injuries and fatalities from occurring as these happened in the first 30 seconds after rupture in most of the incidents examined. Therefore, changing valve spacing or valve closing operators will not impact the safety of gas transmission pipelines.

Calculations indicated that smaller diameter pipelines required longer decompression times; i.e., 12 inch (305 mm) diameter pipelines take about twice as long to blowdown as a 36 inch (914 mm) diameter pipeline of the same length for a worst case full rupture condition due to wall friction effects

CONCLUSIONS

All of the prior research studies and the current review indicate that block valves on gas transmission pipelines do not affect the safety to the public because

1) injuries and fatalities generally occur within the first 30 seconds following gas release and
2) closure of a block valve does not immediately reduce the release of natural gas from the pipeline. Because the natural gas is compressed in the pipeline, it must decompress or blowdown before exiting which can easily take more than one hour depending on the distance of the valve from the rupture.

Manual valves are the most common types of valves that exist on gas transmission pipelines. Examination of the PHMSA incident database and the NTSB gas transmission pipeline incidents indicate that main line block valves on gas transmission are not safety items. Valves are useful for maintenance and line modification but they do not control or affect public safety when a pipeline is involved in an incident.

The review of the PHMSA incident database revealed that the total public damage cost does not correlate with time to make the area safe. The largest public damage costs were associated with an incident that had a 3.5 hour time to make the area safe and a total public damage cost of 87.5 million dollars. The longest time to make the area safe was 116.8 hours and there was no incident cost reported. With one exception, there were incidents with times to make the area safe of 10 hours or more with less than $350,000 damage costs, and the one exception was an incident with a time to make the area safe of 11 hours, which incurred 6.22 million dollars of total damage with only $3000 of public damage and no injuries or fatalities. Thus, these data indicate that rapid shutdown of block valves does not correlate with public safety.

The review of the 13 NTSB gas transmission pipeline incidents indicated that the consequences of the incidents examined would not have been changed if the valves closed immediately after the release of gas or if the valves had been spaced closer together. The incident with the closest block valve spacing of 1.1 mile (0.25 mile upstream and 0.85 mile downstream) [1.8 km {0.4 km upstream and 1.36 km downstream}] had the highest number of fatalities (12) of the 13 NTSB incidents.

In all but one of the NTSB incidents, the injuries and fatalities occurred within 30 seconds after the first release of gas due to either debris, suffocation, or fire. Therefore, even if the valves could be closed instantly, the gas will continue to exit a pipeline for times approaching an hour and thus the number of injuries and fatalities would not have changed. Also, automatic closing valves existed in three of the incidents involving gas transmission lines with only two of the five automatic closing valves closing automatically.

One non-safety problem was identified when parallel pipelines are involved. Operators need pressure and flow information to assist in determining which pipeline in a right of way with multiple pipelines has experienced an incident. This occurred in 50 percent of the NTSB incidents reviewed. The difficulty occurs because when parallel pipelines exist they are linked together with crossovers and the ruptured pipeline can be difficult to identify because all of lines show a pressure decrease due to the open crossovers between the lines trying to equalize the pressure in all the lines. Parallel lines with ruptures need to be quickly identifiable. This is a subject that needs attention.

The most serious incidents with large property damage and the potential for injuries and fatalities involved ignition of the natural gas. This is impossible to prevent and valve spacing or valve actuating method has no effect on whether the gas ignites or not.

Overall, valve spacing has not been identified as a safety issue and should be based on efficient operation and maintenance of the pipelines. Also, this review indicated that the most significant reduction in risk to the public can be achieved by operator application of an integrity management plan to their pipelines to prevent incidents due to external force and third party damage from occurring.

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ATTACHMENT 14

Evangelos Michalopoulos and Sandy Babka – Task Report, "Evaluation of Pipeline Design Factors," Prepared for Gas Research Institute, February 2000, page 20.

EVALUATION OF PIPELINE DESIGN FACTORS

TASK REPORT

(August 1999 – January 2000)

GRI 00/0076

Prepared by:

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Prepared for:

GAS RESEARCH INSTITUTE
Contract No.: 7094

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February 2000

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13. ABSTRACT

This report presents a summary and assessment of design margins used in major pipeline design codes of the U.S. and several other countries. The historical development of the design factors in the ASME B31.8 code is traced. The concept of the traditional historical factor of safety or design margin is related to the more recent developments in reliability-based or limit state design. These are compared to risk-based methods. Based on this review it is recommended that the B31.8 Code Committee begin an in-depth study of the current design practices used for pipelines to take advantage of major improvements in design, construction, materials, welding, and other quality related factors over the last 65 years. It is also recommended that the B31.8 Committee begin to incorporate some form of reliability based, limit states design or some specified risk assessment concepts in pipeline design in order to remain competitive in the international market. Such an undertaking will re-establish the historical leadership role of B31.8 and ASME in the development of international pipeline standards. More importantly, the incorporation of risk based principles should result in reduced risk, improved safety, reduced losses and more economic design, construction and operations of pipelines.

14. SUBJECT TERMS
Pipeline design factors, B31.8, International, Risk Methods, Reliability, 72% SMYS

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Research Summary

TITLE:	Evaluation of pipeline design factors
CONTRACTOR:	The Hartford Steam Boiler Inspection and Insurance Co. GRI Contract No. 7094
PRINCIPAL INVESTIGATOR:	Evangelos Michalopoulos and Sandy Babka
REPORT PERIOD:	August 1999 through January 2000
OBJECTIVES:	To present a summary of design factors from major gas transmission pipeline codes and compare them to recent developments in reliability-based methods in order determine if a change in the design factors of B31.8 is feasible.
TECHNICAL PERSPECTIVE:	The design factors in the B31.8 Code have been in existence for several decades. Over the years there have been improvements in material manufacturing, fabrication, and examination. An examination of these improvements with respect to the existing design factors combined with risk based techniques should improve the design factors. Thus, the pipelines can be constructed more economically without compromising the long safety record.
RESULTS:	This report compiles several gas pipeline codes from the U.S. and other countries and compares the design factors. Risk based methods were also reviewed in an effort to validate their use to improve the existing design factors of B31.8.
TECHNICAL APPROACH:	A literature review was performed to establish the history of the B31.8 Code. Pipeline design codes from the U.S. and several other countries were researched to establish the design factors and the methods used in determining the factors. Risk based methods were examine to ascertain the validity of using them to improve upon the current factors.
PROJECT IMPLICATIONS:	
PROJECT MANAGERS:	GRI Project Manager Dr. Keith Leewis Pipeline Business Unit

EXECUTIVE SUMMARY

This report presents a summary and assessment of design margins used in major U.S. and international pipeline codes.

The historical development of the design factors in the ASME B31.8 code is traced. The major design factors and associated formulas in design codes from the U.S. and several other countries are summarized. The concept of the traditional historical factor of safety or design margin is related to the more recent developments in reliability-based or limit state design. These are compared to risk-based methods.

Based on this review it is recommended that the B31.8 Code Committee begin an in-depth study of the current design practices used for pipelines to take advantage of major improvements in the design, construction, testing, examination, material, welding, analytical techniques and other quality related factors over the last 65 years. The ASME Boiler and Pressure Vessel Code Committee has undertaken such a task in the past few years resulting in an improvement in the design margins for their respective Codes (Upitis and Mokhtarian, 1996 and 1997). This study, performed by the Pressure Vessel Research Council, resulted in a change in the design margin on tensile stress. The margins on yield stress for the Boiler and Pressure Vessel Codes remained unchanged. The design margins in the ASME B & PV Codes, several of the other ASME Piping Codes and the international pressure vessel codes take into consideration the complex configurations of many vessels and more types of loadings, such as thermal and cyclic stresses and areas of stress discontinuities. Transmission piping systems are “simpler” structures, which in most cases are not subject to the same complex design and loading issues as pressure vessels. The design factors in B31.8 are on the Specified Minimum Yield Stress (SMYS). It is believed that the improvements in quality related factors can be taken advantage of in order to improve on the existing design factors.

The potential design factors are summarized in the conclusions and recommendation section, Chapter 9 of this report. The changes in the design factors in B31.8 would result in increases of the design pressure (or maximum operating allowable pressure, MAOP) in the order of 0% to 15% depending on the class location along the pipeline route.

It is also recommended that DOT incorporate the current ASME B31.8 Code requirements in its Pipeline Safety Regulations, Code of Federal Regulations CFR Part 192. The recommended changes in the design factors would result in increases in the DOT allowable design pressure on the order of 6% to 15% depending on the class location.

An additional recommendation is that B31.8 Committee take a leadership role in the development and incorporation of rigorous risk-based design rules. A number of international codes have adopted some forms of reliability based or limit states design and some specified risk assessment concepts in pipeline design. To date, none of the international codes have begun to incorporate design rules based on rigorous risk principles. Such an undertaking will re-establish the historical leadership role of B31.8 and ASME in the development of international pipeline and pressure equipment standards. More importantly, the incorporation of risk based principles should result in reduced risk, improved safety, reduced losses and more economic design, construction and operations of pipelines.

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CHAPTER 1

INTRODUCTION

This report presents a summary and assessment of design margins used in domestic and international pipeline codes throughout the world. Potential changes to the design factors contained in the U.S. pipeline regulations and codes have been recommended as a result of this review. The recommendations allow an increase in the design pressure in many pipelines.

The historical development of the design factors in the ASME B31.8 code is traced in Chapter 2. Design formulas and design requirements in domestic and major international codes are summarized in Chapter 3. The basic design factors are summarized in Chapter 4. Chapter 5 gives an introduction to the traditional historical factor of safety used in various ASME boiler, pressure vessel and piping codes and its relationship to reliability. The concepts of safety factors, design margins and reliability are related in Chapter 6. Reliability and risk-based concepts are presented in Chapter 7. Chapter 8 presents an assessment of present pipeline design margins used as the basis for the recommendations presented in Chapter 9.

The recommended design factors are summarized in the conclusions and recommendations section, Chapter 9 of this report. The changes in the design factors in B31.8 would permit an increase in the design pressure (or maximum operating allowable pressure, MAOP) on the order of 0% to 15% depending on the class location along the pipeline route. Similar changes to DOT rules to make them consistent with recommended B31.8 rules would result in design pressure increases in the order of 6% to 15% depending on the class location.

CHAPTER 2

HISTORICAL REVIEW OF PIPELINE SAFETY MARGINS

Introduction

This chapter contains a historical summary of the safety or design margins in the ASME B31.8 pipeline code. The summary is liberally extracted from Reference 1, the forward of Reference 2 and Reference 8.

Background of B31.8

The code for natural gas pipelines began in the U.S. as a part of the American Standards Association Code for Pressure Piping, ASA B31.1. This code was originally published in 1935 as an American Tentative Standard Code for Pressure Piping covering Power, Gas, Air, Oil and District Boating. After adding Refrigeration to the scope, the ASA B31.1 was published as the American Standard Code for Pressure Piping in 1942. After this time there were additions and/or supplements published in 1944, 1947, and 1951. In all these publications the gas code was characterized under Section 2, Gas and Air Piping Systems. In 1952, the code was subdivided and the gas code became the Gas Transmission and Distribution Piping Systems issued as ASA B31.1.8. This document incorporated material from Sections 2, 6 and 7 of the 1951 Edition of the Pressure Piping Code making it a stand-alone code. In 1952 a new committee was organized to write code material for the new Section 8. The committee was charged with developing code requirements to reflect new materials and methods of construction and operations. The committee made many changes and introduced in the code the design philosophy and concept for the class location. These were incorporated and published in ASA B31.1.8 in 1955. In 1958 further revisions were published in ASA B31.8. Since that time the Section 8 Code Committee has published revisions in 1963, 1966, 1967, 1968, 1975, 1982, 1986, 1989, 1992, and 1995.

Origin of the 72 percent of the SMYS

The appropriate Maximum Allowable Operating Pressure (MAOP) for pipelines was one of the fundamental issues that had to be resolved. The committee had to find some basis for establishing the MAOP for pipelines. Many operators believed that the MAOP should be based on a test pressure. The problem was that pipeline operators were utilizing a wide variety of field pressure tests. Some operators were testing pipelines at 5 to 10 psig over operating pressure. One reason for these relatively low test pressures was that testing was done with gas. In order to establish a consistent rule, the committee thought that a good method would be to base the MAOP on the mill test. Customarily the mill test was 90 percent of the Specified Minimum Yield Strength (SMYS), which would apply to all pipes. The committees agreed that to be consistent, and based on current safe practice, the MAOP for cross-country pipelines should be

80 percent of the 90 percent of SMYS mill test, which is equivalent to 72 percent of the SMYS. The 72 percent of SMYS first appeared in 1935 in the American Standards Association Code for Pressure Piping, ASA B31.1.

The 1951 Edition of the B31.1 Code (ASA B31.1.8), for cross country pipelines included the 72 percent SMYS (80% of 90% mill test) and provided an equation (Barlow) to define wall thickness based on this maximum pressure and nominal wall thickness. Based on good engineering practice and a relatively safe record dating back to early last century, pipeline designs required thicker wall pipe in locations with higher population densities. The B31.1.8 code further identified a thicker wall pipe (or lower stress) for pipe in compressor stations which was limited to a percentage of the 80 percent of mill test as a function of diameter which was; 22% for 0.405 inch OD and smaller pipe; 49% for 3.5 inch OD pipe; 72% for 8.625 inch OD pipe and 90% for 24 inch OD and larger pipe. Therefore, for large diameter pipe in compressor stations percent of SMYS allowed would have been 90% x 80% x 90% hence 65% of SMYS. The only other limit on MAOP was 50 percent SMYS inside boundaries of cities and villages.

As mentioned previously the gas code was first issued as a stand-alone code in 1952 in ASA B31.1.8 Gas Transmission and Distribution Piping Systems. The Section 8 Code Committee was charged with the responsibility of maintaining and updating the code. Over a two and one half year period this Committee developed the ASA B31.1.8 – 1955 Gas Transmission and Distribution Piping Systems Code. During this time the MAOP was one of the items that was considered. Prior to the 1955 Edition of B31.1.8 time the gas transmission code limited the MAOP to 72 percent SMYS (80% of the mill test) in all locations except "inside incorporated limits of towns and cities" and certain limits in compressor stations. The MAOP in these areas were limited to 50% in towns and 63% in compressor stations.

Some committee members believed that MAOP should be based on the field test. Hydrostatic testing with a water column was performed by some operators at much higher pressures than had been performed in the past. However, other operators had done and were doing field pressure tests with gas at much lower pressures since hydrostatically testing at higher pressures was unacceptable to these operators. For this reason basing MAOP on testing was unacceptable. The consensus solution was finally found in adopting the long established practice of using 80 percent of 90 percent mill test pressure for MAOP in cross-country pipelines.

There was a realization by this Committee that there was a need to consider intermediate levels of pipeline stress levels (or wall thicknesses) based on population density and other special conditions.

Establishing Appropriate Wall Thickness (Stress Levels) for Class Locations

In 1955 the second edition of the American Standard Code for Pressure Piping, Section 8, ASA B31.1.8 – 1955 Gas Transmission and Distribution Piping Systems was published. This document was the first to designate four types of construction to be used based on population density. Prior to this, the old code generally permitted a maximum operating hoop stress of 72 % SMYS in all locations except those inside incorporated limits of cities and towns. In these areas a heavier wall thickness was required and operational history had shown that a maximum hoop stress of approximately 50% SMYS should be specified. By specifying maximum hoop stress the designs could be simplified and all diameters of pipe would be accounted for. Between 1952 and 1955 the Section 8 Subcommittee realized that there was a need to differentiate areas of population density and establish hoop stress limits below 72% SMYS that would be appropriate in each area to protect the public safety. Many operators were reducing the stress levels below 72% SMYS in certain areas although there was no code criteria to indicate what intermediate stress levels should be used for the various degrees of population density. These operators had adopted various lower stress levels for population density areas, as well as, road and railroad crossings but the criteria were not uniform among operators.

In order to study and evaluate how population densities could be classified and appropriate pipe hoop stress limits could be established, the Section 8 Committee formed a subgroup to address this problem. The subgroup elected to use a ½ mile corridor with the pipeline in the centerline and establish areas of population density within the corridor in running miles along the pipeline. An aerial survey of many miles of existing major pipelines was made to see what percentages of these pipelines would be impacted by areas of population density where lower stress levels should be applied to enhance public safety. A consulting engineering firm was engaged to evaluate the results. At the time of this study, it was found that about 5% of the total pipelines surveyed would be impacted by population density requiring stress levels below 72% SMYS. The subgroup determined that the population density in the ½ mile corridor traversed by the pipeline should be evaluated according to a building count along 1 mile and 10 mile sections to establish a population index to define hoop stress limits. From this study it was determined that the following class location categorization based on a population density index was needed:

Class 1, (72% SMYS) Sparsely Populated Areas
Class 2, (60% SMYS) Moderately Developed Areas
Class 3, (50% SMYS) Developed Residential and Commercial
Class 4, (40% SMYS) Heavy Traffic and Multistory Buildings

In addition, types of construction were established as follows:

Type A (72% SMYS)
Type B (60% SMYS)
Type C (50% SMYS)
Type D (40% SMYS)

The type of construction identified the wall thickness or hoop stress certain locations. For example uncased highways and railroad crossing in a Class 1 (72% SMYS) location would require a Type B (60% SMYS) construction in the crossing.

It is important to note that the ½ mile corridor width suggested establish the population density was not selected as one that would be a hazardous zone in the event of pipeline failure. The ½ mile corridor was conveniently the same as the width of typical aerial photographs of that time. The aerial photographs could be used to evaluate nearby activities that might threaten pipeline safety in the future.

Pipeline engineers assumed that the greater population density increased the chances of an incident which may cause damage to the pipeline. Some of these activities are trenching for water and sewer lines, terracing cutting for streets and other digging in the proximity of the pipeline. The lower stress levels are used so that in the event of outside damage to the pipeline from these activities the pipeline is less likely to fail and cause a hazard to the public.

The Federal Regulations 49 (CFR 192) were issued in 1970 as a result of the Pipeline Safety Act of 1968, by the Office of Pipeline Safety (OPS). Although OPS adopted much of the 1968 Edition of ASME B31.8, they reduced the corridor width from the arbitrary ½ mile to today's ¼ mile. This was done in a Notice of Proposed Rule Making (NPRM) which was as follows:

> "A recent study that included hundreds of miles of pipeline right-of-ways areas indicated that a zone of this width is not necessary to reflect the environment of the pipeline. A ¼ mile wide zone extending one-eighth of a mile on either side of the pipeline appears to be equally appropriate for this purpose. It would be an unusual instance in which a population change more than one-eighth of a mile away would have an impact on the pipeline. Conversely, an accident on the pipeline would rarely have an effect on people or buildings that were more than an eighth of a mile away. For these reasons it appears that the density zone can be reduced from one-half to one-quarter of a mile without any adverse effect on safety"

Development of 80 Percent SMYS MAOP

In the early 1950's, testing equipment, procedures and technology were developed to pressure test pipelines with gas. Some operators began at higher pressures with water in contrast to the more risky testing with gas. Some operators readily recognized the value of hydrostatic testing as a new tool to prove the integrity of the pipeline. Some operators were hydrostatically testing to 100% of the actual minimum yield strength as determined by the steel mill metallurgical test. One operator determined the actual minimum yield strength by hydrostatic test and plotted the internal pressure versus pump volume. The pressure-volume plot was a straight line confirming the elasticity of the steel. The actual minimum yield strength was defined when the slope of the line became one-half the slope of the straight line elastic portion of the plot as the pipe began to yield. By using actual minimum yield strength, MAOP's much greater than those based on the 72 % of SMYS were established. This allowed operators to set the MAOP to 80% of the actual strength of the structure rather than to 80% of what the pipe mills would guarantee (i.e. 90% of the specified yield). Hydrostatic testing to SMYS provided an additional level of safety. Essentially all defects that might result in failure near MAOP and were missed by prior inspections were discovered by pressure testing to actual minimum yield strength of the pipeline.

After approximately 16 years of research, study and testing to prove the value of pressure testing to actual minimum yield strength the practice was documented and published in the AGA REPORT L 30050 (Duffy et. al 1968). Many in the pipeline industry realized the merits of hydrostatic testing to actual minimum yield to:

1) Increase the known safety margin between MAOP and test pressure
2) Prove the feasibility of operating safely above 72% SMYS with a greater known safety factor
3) Remove defects that might fail in service
4) Improve the integrity of the pipe

Based on this experience, a proposal was made around 1966 to ASME B31.8 Code Committee to allow operation the of pipelines above 72% SMYS. Unfortunately the proposal to allow the operation of pipelines at 80% SMYS received some unresolved negative votes which precluded inclusion in the 1968 Edition of ASME B31.8 (the Code). However, before the B31.8 Code Committee could resolve the negatives votes and finalize Code material to allow the operation of pipeline at 80% SMYS, the Pipeline Safety Act of 1968 was enacted. In 1968, the Office of Pipeline Safety (OPS) adopted the 1968 Edition of ASME B31.8 as an interim safety standard until 1970 at which time OPS issued the final rules, Title 49 Code of Federal Regulations Part 192 (49 CFR 192, the regulations). Title 49 CFR 192 was taken almost verbatim from the 1968 Edition of ASME B31.8, hence, the MAOP in Class 1 locations for pipelines installed after November 11, 1970 required 72% SMYS. Those pipelines built before November 11, 1970 operating above 72% SMYS could continue operating at these pressures if they qualified under the "grandfather clause" in the Federal Regulations. The "grandfather clause" essentially said not withstanding all other requirements for establishing MAOP for new pipeline that:

> "...an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970...",

subject to the requirements of change in class location.

The "grandfather clause" is for pipelines built before the Federal Regulations were issued. When a class location change occurs, that portion of the pipeline within the new class location must meet the requirements of a new pipeline, i.e., a pipeline under the "grandfather clause" that operates over 72% SMYS would no longer be able to operate above 72% SMYS. New pipelines constructed after the Federal Regulations were issued, could not be qualified above 72 % SMYS in the United States.

After the Federal Regulations became effective many operators failed to see a role for the ASME B31.8 in the regulatory environment. At this time the B31.8 essentially disbanded. However, in 1974 operators realized that unless the code was updated or reaffirmed by 1975 the code would be withdrawn in accordance with ASME policy. It was realized that the code was essential for bid purposes and guidance internationally. In addition, American valve manufacturers and fabricators would be forced to build to foreign specifications in the absence of the ASME B31.8 Code, which references U.S. specifications and standards for valves. It became apparent that unless the B31.8 Code was maintained that American manufacturers would be required to use foreign standards and specifications. The B31.8 Code is presently utilized in the Middle East, North and South America and many other areas internationally. Consequently, the Code Committee was reorganized in 1974 and published the 1975 Edition to preserve the Code.

In the latter part of the 1970's, the proposal to allow pipelines to operate up to 80% SMYS was again submitted to the ASME B31.8 Code Committee. The Committee worked several years to develop criteria and requirements for the design, hydrostatic testing and ductile fracture control for pipelines to be operated up to 80% SMYS. The greatest opposition came from pipe manufacturing members who were on the Committee. The pipeline operator Committee members realized that transporting gas at 80% SMYS would be a great economic advantage, however, the pipe manufacturing members envisioned reduced profits from the sale of thinner wall. The Committee finally resolved all the issues involved in design, hydrostatic testing, and ductile fracture control and approved provisions for pipelines to operate up to 80% SMYS. The allowance to operate pipelines to maximum limit in onshore Class 1 locations was published in the ASME B31.8a – 1990 Addenda to the B31.8 1989 Edition.

Conclusions

The code for natural gas pipelines originated as an American Standards Association code for pressure piping. Committee members believed that the MAOP should be based on a pressure test, however, the operators were using a wide variety of maximum field test pressures. For consistency, the Committee decided to use 80% of the pipe mill manufacturer's guarantees which were 90% minimum specified yield strength. Thus, the MAOP for rural cross country pipelines was established as 72% SMYS and was published in the 1935 Edition of the American Standards Association Code for Pressure Piping ASA B31.1.

The ASME B31.1.8 – 1955 Gas Transmission and Distribution Piping Systems was the first to designate class locations based on population density. Prior to this the code had generally allowed 72% SMYS for cross country pipelines and 50% SMYS for pipelines inside incorporated limits of town and cities. The Committee had a study done that indicated only 5% of the pipeline would require lower stress levels due to population density. The original corridor was set at ½ mile with the pipeline in the centerline. The corridor was later reduced to ¼ mile in the 1970 49 CFR 192 followed by ASME B31.8 in the 1982 Edition. As a result of a detailed study it was determined that four stress levels would be the simplest method to categorize the design factors. These four were Class 1 (72% SMYS), Class 2 (60% SMYS), Class 3 (50% SMYS), and Class 4 (40% SMYS).

Beginning in the early 1950's hydrostatic testing developed as a major tool to prove the integrity of the pipe. After many years of research and development operators realized the value of testing pipe to actual yield strength. Some operators were using the actual minimum yield strength to determine MAOP. One operator established MAOP's at 80% of the actual hydrostatic yield strength which in some cases was over 80% SMYS. Based on almost 40 years of research, testing, and operational experience, the ASME B31.8 Committee developed code requirements for establishing an 80% SMYS MAOP. This provision was published in ASME B31.8a – 1990 Addenda to the B31.8 – 1989 Edition.

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CHAPTER 3

SUMMARY OF DESIGN FORMULAS FROM VARIOUS CODES

This chapter summarizes the basic design formulas and requirements of major domestic and international pipeline codes. The main objective of this summary is to assess the design factors used in the various codes for the purpose of making recommendations to B31.8 for possible code improvements. All Codes used in this summary are current as of the date of this report.

ASME B31.4 Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (Ref. 1)

Pressure Design of Straight Pipe (Par. 404.1.2)

The internal pressure design wall thickness, t, of steel pipe shall be calculated by the following equation

$$t = \frac{P_i D}{2S} \qquad\qquad t = \frac{P_i D}{20S} \text{ in metric units}$$

The nominal wall thickness of straight sections of steel pipe shall be equal to or greater than t_n determined in accordance with the following formula

$$t_n = t + A$$

where,

t	=	pressure design wall thickness, in. (mm)
t_n	=	nominal wall thickness satisfying requirements for pressure and tolerances, in. (mm)
A	=	sum of allowances for threading, grooving, corrosion, etc., in. (mm)
P_i	=	internal design gage pressure, psi (bar)
D	=	outside diameter, in. (mm)
S	=	applicable allowable stress value, psi (MPa)

Allowable Stress Value (Par. 402.3.1)

The allowable stress value, S, to be used in the calculations shall be established as follows:

S = 0.72 x E x Specified Minimum Yield Strength of pipe, psi (MPa)

where

0.72	=	design factor on nominal wall thickness
E	=	weld joint factor

Limits of Calculated Stresses Due to Occasional Loads (Par. 402.3.3)

The sum of longitudinal stresses produced by pressure, live and dead loads, and those produced by occasional loads, such as wind and earthquake, shall not exceed 80% of the specified minimum yield strength of the pipe. It is not necessary to consider wind and earthquake as occurring concurrently.

Expansion and Flexibility (Par. 419)

The maximum computed expansion stress range, S_E , without regard to fluid pressure stress, based on 100% of the expansion, with modulus of elasticity for the cold condition – shall not exceed the allowable stress range, S_A , where S_A=0.72 SMYS.

The sum of longitudinal stresses due to pressure, weight and other external loadings shall not exceed $0.75S_A$ or 0.54 SMYS.

The sum of the longitudinal stresses produced by pressure, live and dead loads, and those produced by occasional loads, such as wind and earthquake, shall not exceed 80% of the specified minimum yield strength of the pipe (0.8 SMYS). It is not necessary to consider wind and earthquake occurring concurrently.

ASME B31.8 Gas Transmission and Distribution Piping Systems

Steel Pipe Design Formula (Par. 841.11)

The design pressure for steel gas piping systems or the nominal wall thickness for a given design pressure shall be determined by the following formula:

$$P = \frac{2St}{D}FET \qquad\qquad t = \frac{PD}{2SFET}$$

where

P	=	design pressure, psi
S	=	specified minimum yield strength, psi
D	=	nominal outside diameter of pipe, in.
t	=	nominal wall thickness, in.
F	=	design factor. In setting the design factor due consideration has been given and allowance has been made for the various underthickness tolerances provided for in the pipe specifications listed and approved for usage in this Code.
E	=	longitudinal joint factor
T	=	temperature derating factor

Design Factor F (Par. 841.114)

The design factor is a function of location class. The basic design factor is given in Table 841.111A in the Code and is reproduced below:

TABLE 841.111A
BASIC DESIGN FACTOR F

Location Class	Design Factor F
Location Class 1, Division 1	0.80
Location Class 1, Division 2	0.72
Location Class 2	0.60
Location Class 3	0.50
Location Class 4	0.40

The above basic design factors are used for pipelines, mains and service lines. There are exceptions (modification to the design factor) that apply to crossings of roads, railroads, parallel encroachment of pipelines and mains on roads and railroads, fabricated assemblies, pipelines on bridges, compressor station piping and near concentration of people in Location Classes 1 and 2. The values range from the basic design factor to a lower value of 0.50, except for Location Class 4 which is always 0.40. The complete Table 841.114B is reproduced below.

TABLE 841.114B
DESIGN FACTORS FOR STEEL PIPE CONSTRUCTION

	Location Class				
	1				
Facility	Div. 1	Div. 2	2	3	4
Pipelines, mains, and service lines [see para. 840-2(b)]	0.80	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.72	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.80	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.60	0.50	0.40
Fabricated assemblies (see para. 841-121)	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges (see para. 841-122)	0.60	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.50	0.40
Near concentration of people in Location Classes 1 and 2 [See para. 840.3(b)]	0.50	0.50	0.50	0.50	0.40

Location Class (Par. 840.2)

The location class is a function of the number of buildings intended for human occupancy near the pipeline. An area ¼ mile wide along the route of the pipeline and 1 mile in length is used to determine the number of buildings for location class categorization. The location classes are defined as follows:

Location Class 1
A Location Class 1 is any 1 mile section that has 10 or fewer buildings intended for human occupancy. It is intended to cover areas such as wasteland, deserts, mountains, grazing land, farmland, and sparsely populated areas.

Location Class 1, Division 1
A location where the design factor is greater than 0.72 but equal or less than 0.80 and has been hydrostatically tested to 1.25 the maximum operating pressure.

Location Class 1, Division 2
A location where the design factor is equal or less than 0.72 and the pipe has been hydrostatically tested to 1.1 times the maximum operating pressure.

Location Class 2
A location in any 1 mile section that has more than 10 but fewer than 46 buildings intended for human occupancy. It is intended for fringe areas around cities and towns, industrial areas, ranch or country estates, etc.

Location Class 3
A location in any 1 mile section that has 46 or more buildings intended for human occupancy. It is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas and other populated areas not in Location Class 4.

Location Class 4
This location class includes areas where multistory buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground.

Temperature Derating Factor T for Steel Pipe (Par. 841.116)

The effects of temperature on the allowable stress is included through the temperature derating factor shown below:

TABLE 841.116A
TEMPERATURE DERATING FACTOR T
FOR STEEL PIPE

Temperature, ^{o}F	Temperature Derating Factor T
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

From the above table it is seen that the maximum temperature that the Code covers is 450 ^{o}F.

Expansion and Flexibility and Longitudinal Stresses (Par. 832)

The maximum combined (bending and torsional) expansion stress, S_E, shall not exceed 0.72S, where S is the specified minimum yield strength, psi.

In addition the total of the following shall not exceed the specified minimum yield strength, S:

a) the combined stress due to expansion, S_E
b) the longitudinal pressure stress
c) the longitudinal bending stress due to external loads, such as weight of pipe and contents, wind, etc.

The sum of (b) and (c) above shall not exceed 0.75S.

Canadian Standard: CSA Z662-99 Oil and Gas Pipeline Systems (Clause 4.3.3)

The Canadian Standards Association Standard Z662 gives the following equation for the design pressure for a straight pipe:

$$P = \frac{2St}{D} x 10^3 x F x L x J x T$$

where

P	=	design pressure, kPa
S	=	specified minimum yield strength, MPa
t	=	design wall thickness, mm
D	=	outside diameter of pipe, mm
F	=	design factor
L	=	location factor
J	=	joint factor
T	=	temperature factor

Design Factor F

The design factor to be used in the formula above is 0.8.

Location Factor (L) for Steel Pipe

The location factor is given in the Table 4.1 in the Standard and is included in this report for convenience.

Table 4.1
Location Factor for Steel Pipe
(See Clauses 4.3.3.3 and 15.4.1.3)

Application	Location factor (L)			
	Class 1 location	**Class 2 location**	**Class 3 location**	**Class 4 location**
Gas (Non-sour service)				
General and cased crossings	1.00	0.90	0.70	0.55
Roads*	0.75	0.625	0.625	0.50
Railways	0.625	0.625	0.625	0.50
Stations	0.625	0.625	0.625	0.50
Other	0.75	0.75	0.625	0.50
Gas (Sour service)				
General and cased crossings	0.90	0.75	0.625	0.50
Roads*	0.75	0.625	0.625	0.50
Railways	0.625	0.625	0.625	0.50
Stations	0.625	0.625	0.625	0.50
Other	0.75	0.75	0.625	0.50
HVP and CO_2				
General and cased crossings	1.00	0.80	0.80	0.80
Roads*	0.80	0.80	0.80	0.80
Railways	0.625	0.625	0.625	0.625
Stations	0.80	0.80	0.80	0.80
Other	0.80	0.80	0.80	0.80
LVP				
All except uncased railway crossings	1.00	1.00	1.00	1.00
Uncased railway crossings	0.625	0.625	0.625	0.625

*For gas pipelines, it shall be permissible to use a location factor higher than the given value, but not higher than the applicable value given for "general and cased crossings," provided that the designer can demonstrate that the surface loading effects on the pipeline are within acceptable limits (see Clause 4.6).

Notes:

(1) Roads: Pipe, in parallel alignment or in uncased crossings, under the travelled surface of the road or within 7 m of the edge of the travelled surface of the road, measured at right angles to the centreline of the travelled surface.

(2) Railways: Pipe, in parallel alignment or in uncased crossings, under the railway tracks or within 7 m of the centreline of the outside track, measured at right angles to the centreline of the track.

(3) Stations: Pipe in, or associated with, compressor stations, pump stations, regulating stations, or measuring stations, including the pipe that connects such stations to their isolating valves.

(4) Other: Pipe that is

(a) supported by a vehicular, pedestrian, railway, or pipeline bridge;

(b) used in a fabricated assembly; or

(c) within five pipe diameters in any direction of the last component in a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend that is not associated with the fabricated assembly.

Joint Factor (J) for Steel Pipe

The joint factor to be used in the design formula shall not exceed the applicable value given in Table 4.2. For welded pipe, Table 4.2 applies to pipe having a longitudinal seam or a helical seam.

Table 4.2 Joint Factor for Steel Pipe	
Pipe Type	Joint Factor (J)
Seamless	1.00
Electric Welded	1.00
Submerged arc welded	1.00
Continuous welded	0.60

Temperature Factor (T) for Steel Pipe

The temperature factor for steel pipe is given below:

Table 4.3 Temperature Factor for Steel Pipe		
Temperature, °F	Temperature, °C	Temperature Factor (T)
Up to 248	Up to 120	1.00
302	150	0.97
356	180	0.93
392	200	0.91
446	230	0.87

Wall Thickness Allowances

The nominal wall shall not be less than the design wall thickness, *t*, plus allowances for corrosion, threading and for grooved pipe. In determining the nominal wall thickness, the consideration of manufacturing tolerances is not required.

Flexibility and Stress Analysis

Hoop Stress

The hoop stress used in the stress analysis for any location on the pipeline shall be calculated using the following formula:

$$S_h = \frac{PD}{2t_n} x\, 10^{-3}$$

where

S_h	=	hoop stress, MPa
t_n	=	pipe nominal wall thickness, less allowances, mm
P	=	design pressure, kPa
D	=	outside diameter of pipe, mm

Combined Hoop and Longitudinal Stresses

The hoop stress due to design pressure combined with the net longitudinal stress due to the combined effects of pipe temperature changes and internal fluid pressure shall be limited in accordance with the following formula:

$$S_h - S_L \leq 0.90\, S \text{ x } T$$

Note that this formula does not apply if S_L is positive (i.e. tension.)

The longitudinal compression stress is calculated using the following formula:

$$S_L = \nu\, S_h - E_c\, \alpha\, (T_2 - T_1)$$

where

S_h	=	hoop stress due to design pressure, MPa
S_L	=	longitudinal compression stress, MPa
ν	=	Poisson's ratio
α	=	linear coefficient of thermal expansion, $^{o}C^{-1}$
E_c	=	modulus of elasticity of steel, MPa
T_2	=	maximum operating temperature, ^{o}C
T_1	=	ambient temperature at time of restraint, ^{o}C
S	=	specified minimum yield strength, MPa
T	=	temperature factor

Combined Stresses for Restrained Spans

For those portions of restrained pipelines that are freely spanning or supported aboveground, the combined stress shall be limited in accordance with the following formula:

$$S_h - S_L + S_B \leq S \times T$$

where symbols are defined above, except for

S_B	=	absolute value of beam bending compression stress resulting from live and dead loads, MPa

Stresses Design for Unrestrained Portions of Pipeline Systems

The thermal expansion stress range, based on 100% of the expansion, shall be limited in accordance with the following formula:

$$S_E \leq 0.72\, S \times T$$

where,

S_E	=	thermal expansion stress, MPa
S	=	specified minimum yield strength, MPa
T	=	temperature factor

The sum of the longitudinal pressure stress and the total bending stress due to sustained force and wind loading shall be limited in accordance with the following formula:

$$0.5\, S_h + S_B \leq S \times F \times L \times T$$

where symbols have been defined previously above.

Guidelines for Risk Assessment of Pipelines

This standard contains a non-mandatory appendix which provides guidelines on the application of risk assessment to pipelines. These guidelines identify the role of risk assessment within the context of an overall risk management process, provide a standard terminology, identify the components of the risk assessment process and provide reference to methodological guidelines for risk assessment.

Limit States Design

The standard also provides a non-mandatory appendix for limit states design. Limit states as defined in this standard means a reliability-based design method that uses factored loads (nominal or specified loads multiplied by a load factor) and factored resistances (calculated strength, based on nominal dimensions and specified material properties multiplied by a resistance factor).

This type of design in the U.S. is also referred to as the partial safety factor approach. It should not be confused with limit load or plastic analysis.

British Standard: BS 8010 Section 2.8 Steel for Oil and Gas

This section of the British Standard BS 8010: Part 2 provides guidance on the design, construction and installation of steel pipelines on land for oil, gas and toxic fluids.

The design equations cover the calculation of hoop stress and the calculation of expansion and flexibility stress and their appropriate allowable stress limits.

Hoop Stress (Clause 2.9.2)

The hoop stress can be calculated by using either the thin wall or thick wall design equation:

Thin wall

$$S_h = \frac{pD}{20t}$$

Thick Wall

$$S_h = \frac{p(D^2 + D_i^2)}{10(D^2 - D_i^2)}$$

where

S_h	=	hoop stress (N/mm^2)
p	=	internal design pressure (bar)
D	=	outside diameter (mm)
t	=	design thickness (mm)
D_i	=	inside diameter (D-2t) (mm)

The thick wall design equation gives more accurate calculation of hoop stress and always gives the smallest value of maximum stress. Where the D/t ratio is greater than 20, the difference between the stresses calculated between the two formulae is less than 5%.

Longitudinal Stress

The total longitudinal stress should be the sum of the longitudinal stress arising from pressure, bending, temperature, weight, other sustained loadings and occasional loadings.

For totally restrained sections of a pipeline, the longitudinal tensile stress resulting from the combined effects of temperature and pressure change alone should be calculated as follows:

Thin Wall

$$S_{L1} = \nu S_h - E\alpha(T_2 - T_1)$$

Thick Wall

$$S_{L1} = \nu\left(S_h - \frac{p}{10}\right) - E\alpha(T_2 - T_1)$$

where

S_{L1}	=	longitudinal tensile stress (N/mm^2)
ν	=	Poisson's ratio (0.3 for steel)
p	=	internal design pressure (bar)
S_h	=	hoop stress using the nominal pipe wall thickness (N/mm^2)
E	=	modulus of elasticity (N/mm^2) (2.0 x 10^5 at ambient temperature for carbon steel)
α	=	linear coefficient of thermal expansion (per ^{o}C) (11.7x10^6 per ^{o}C, up to 120 ^{o}C for Carbon Steel)
T_1	=	installation temperature (^{o}C)
T_2	=	maximum or minimum temperature (^{o}C)

For unrestrained section of a pipeline, the longitudinal tensile stress resulting from the combined effects of temperature and pressure change alone should be calculated as follows:

Thin Wall

use $k = 1$ in the following thick wall formula

Thick Wall

$$S_{L2} = \frac{S_h}{k^2 + 1} + \frac{1000 M_b i}{Z}$$

where

S_{L2}	=	longitudinal tensile stress (N/mm^2)
M_b	=	bending moment applied to the pipeline (N•m)
i	=	stress intensification factor
k	=	ratio of D/D_i
Z	=	pipe section modulus (mm^3)

Shear Stress

The shear stress should be calculated from the torque and shear force applied to the pipeline as follows:

$$\tau = \frac{1000T}{2Z} + \frac{2S_F}{A}$$

where

τ	=	shear stress (N/mm^2)
T	=	torque applied to the pipeline (N•m)
S_F	=	shear force applied to the pipeline (N)
A	=	cross sectional area of the pipe wall (mm^2)
Z	=	pipe section modulus (mm^3)

Equivalent Stress

The equivalent stress should be calculated using the von Mises equivalent stress criteria as follows:

$$S_e = (S_h^2 + S_L^2 - S_h S_L + 3\tau^2)^{1/2}$$

where

S_h	=	hoop stress using the nominal pipe wall thickness (N/mm^2)
S_L	=	total longitudinal stress (N/mm^2)
τ	=	shear stress (N/mm^2)

Limits of Calculated Stress

Allowable Hoop Stress

The allowable hoop stress (S_{ah}) should be calculated as follows:

$$S_{ah} = a\, e\, S_y$$

where

S_{ah}	=	allowable hoop stress (N/mm^2)
a	=	design factor
e	=	weld joint factor
S_y	=	specified minimum yield strength of pipe (N/mm^2)

Allowable Equivalent Stress

The allowable equivalent stress should be calculated as follows:

$$S_{ae} = 0.9\ S_y$$

where

S_{ae}	=	allowable equivalent stress (N/mm^2)
S_y	=	specified minimum yield strength of the pipe (N/mm^2)

Design Factor

The maximum design factor *a* to be used in the calculation of allowable stress for pipelines should be :

Category B substances
The design factor *a* should not exceed 0.72 in any location. In high population density areas consideration for extra protection should be given. Code provides typical examples of extra protection measures.

Category C and Category D substances
The design factor *a* should not exceed 0.72 in class 1 and 0.30 in class 2 and class 3 locations. However, the design factor may be raised to a maximum of 0.72 in class 2 locations providing it can be justified to a statutory authority by a risk analysis carried out as part of a safety evaluation for the pipeline.

Pipelines designed to convey Category D substances in class 2 locations should be given either a nominal wall thickness of 9.52 mm (0.375 in.) or be provided with impact protection to reduce the likelihood of penetration from mechanical interference.

It is essential than pipelines designed to operate in class 3 locations be limited to a maximum operating pressure of 7 bar (101.5 psi).

Categorization of Substances

Substances should be placed in one of the following four categories according to the hazard potential of the substance.

Category A
Typically water based fluids

Category B
Flammable and toxic substances which are liquids at ambient temperature and atmospheric pressure conditions. Typical examples would be oil, petroleum products, toxic liquids and other liquids which could have an adverse effect on the environment if released.

Category C
Non flammable substances which are gases at ambient temperature and atmospheric pressure conditions. Typical examples would be oxygen, nitrogen, carbon dioxide, argon and air.

Category D
Flammable and toxic substances which are gases at ambient temperature and atmospheric pressure condition and are conveyed as gases or liquids. Typical examples would be hydrogen, methane, ethane, ethylene, propane, butane, liquefied petroleum gas, natural gas liquids, ammonia and chlorine.

Classification of Location

The location of Category C and D substance pipelines should be classified in relation to population density along the route of the pipeline to determine the operating stress levels and the proximity distances from normally occupied buildings.

The location of Category B substance pipelines need not be classified in relation to population density but may require extra protection or be subject to safety evaluation.

Class 1 Location
Areas with population density less than 2.5 persons per hectare

Class 2 Location
Areas with population density greater than or equal to 2.5 persons per hectare and which may be extensively developed with residential properties, schools and shops, etc.

Class 3 Location
Central areas of towns and cities with a high population and building density, multi-story buildings, dense traffic and numerous underground services.

The code also contains requirements for the proximity to occupied buildings and requirements for the calculation of population densities.

Safety Evaluation

The pipeline designer should give consideration to the preparation of a safety evaluation. The evaluation should include the following:

a) critical review of pipeline route;
b) description of technical design including potential hazards of the substance to be conveyed and design and construction aspects of the pipeline system;
c) details of pressure control, monitoring and communication systems, emergency shutdown facilities and leak detection (where incorporated);
d) proposals for pipeline monitoring and inspection during operation together with emergency procedures.

Risk Analysis

Where a risk analysis is required as part of the safety evaluation it should include the following:

a) the identification of all potential failure modes;
b) a statistically based assessment of failure mode and frequency;
c) a detailed evaluation of the consequences of failure from small holes up to full bore rupture including reference to population density;
d) prevailing weather conditions;
e) time taken to initiate a pipeline shutdown.

The risk analysis should culminate in an evaluation of risk along the pipeline.

German Standard: DIN 2413 Part 1 Design of Steel Pressure Pipes

The German Standard DIN 2413 Part 1 covers the design of steel pressure pipes with circular cross-sectional shape and ratio of outside to inside diameter, d_a / d_i , up to 2.0, for the following service conditions (referred to load cases I through III).

I. Pipes subjected to predominantly static loading and rated for a temperature up to 120 °C.
II. Pipes subjected to predominantly static loading and rated for temperature over 120 °C.
III. Pipes subjected to fatigue loading and rated for a temperature up to 120 °C.

For loading case I, which is referenced by DIN 2470 Part 2, the design wall thickness is given by the following equation:

$$s_v = \frac{d_a\, p}{2\sigma_{zul}\, v_N} \quad \textit{and} \quad \sigma_{zul} = K / S = Y\, K$$

where

s_v	=	Design wall thickness of pipe, not including relevant design factors, N/mm^2
d_a	=	Pipe outside diameter, mm
p	=	Design pressure, mm
σ_{zul}	=	Maximum permissible stress under static loading, N/mm^2
v_N	=	Degree of utilization of the design stress in the weld
K	=	Characteristic strength value, N/mm^2
S	=	Safety factor for fatigue strength
Y	=	Degree of utilization = 1/S

The characteristic strength, K, is the yield strength or 0.2% proof strength or 0.5% proof strength (specified minimum values at 20 °C).

The required thickness shall be calculated from the following equation:

$$s = s_v + c_1 + c_2$$

where

s	=	Required wall thickness of pipe, including relevant design factors, mm
c_1	=	Factor to allow for the lower limit deviation for wall thickness, mm
c_2	=	Factor to allow for corrosion or wear, mm

DIN 2470 Part 2 Steel Gas Pipelines

The German Standard DIN 2470 Part 2: Steel Gas Pipelines for Permissible Working Pressures exceeding 16 bar Pipes and Fittings, provides requirements for steel pipes and fittings used for public gas supply lines rated for permissible working pressures exceeding 16 bar (232 psi). Part 1 applies to pressures up to 16 bar.

The pipe wall thickness shall be designed as specified in DIN 2413, Category I. The factor of safety S to be used in the design of buried gas pipelines varies from 1.50 to 1.60 for the steel grades covered in this standard. The small variation is associated with the minimum elongation after fracture of the steels.

The above factors cover normal stressing imposed by laying under ground. If additional stressing of a special nature exists (e.g. in the case of lines above ground or an earth cover more than 3 m when the ratio s/d_a is not greater than 1%) additional verification of the stress conditions shall be carried out. s and d_a are the nominal thickness and the outside diameter of the pipe, respectively.

European Standard: PrEN 1594 Pipelines for Gas Transmission

The European draft Standard PrEN 1594 Pipelines for Gas Transmission applies to pipelines for on land gas supply systems with Maximum Operating Pressure (MOP) greater than 16 bar (232 psi). The design temperature of the system is equal to or greater than –40 ^{0}C and lower than 120 ^{o}C.

Design

For the determination of the wall thickness, a distinction is made between standard and non standard cases. Most cases can be treated as standard.

Hoop Stress Due to Internal Pressure

For standard cases it is sufficient to calculate the hoop stress due to internal pressure:

$$\frac{DP\ x\ D}{20T_{\min}} \le f_o\ x\ R_{t\,0.5}$$

where

DP	=	design pressure, bar
D	=	outside diameter of pipe, mm
	=	$D_i + 2T_{min}$ if D_i is preset
D_i	=	is the inside diameter, mm
T_{min}	=	minimum wall thickness, mm
f_o	=	design factor
$R_{t\,0.5}$	=	specified minimum yield strength, N/mm^2

Design Factor (f_o)

The design factor (f_o) for the internal pressure to be used for the pipeline section in question is as follows:

- underground sections, except stations ≤ 0.72
- pipelines in tunnels continuously supported ≤ 0.72
- stations ≤ 0.67

Criteria for Nonstandard Cases

Nonstandard cases involve the following areas;

- settlement areas;
- mining subsidence areas;
- frost heave areas;
- landslide areas;
- earthquake areas;
- areas of future planned increase in soil cover, local embankments etc.

The standard provides a number of annexes (appendices) that provide calculation methods and requirements for the above cases.

In addition, the designer shall take into account all other circumstances that may require calculation as nonstandard case, such as;

- higher pipe temperature and/or large temperature differences in relation to special pipe configurations;
- any circumstances that may lead to excessive construction settlement differences as a result of the construction techniques employed;
- aboveground pipelines locally supported.

Wall Thickness Determination for Nonstandard Cases

In the nonstandard case the wall thickness determination comprises of an analysis of the loads and displacements and an analysis of the stresses and strains which may occur.

The PrEN 1594 Standard provides requirements for buried pipelines, pipe/soil interaction analysis methods, above ground pipeline sections and structural models for pipelines.

Analysis Based on Elastic Theory

When axial and tangential stresses have been determined they are combined to give the stress resultant σ_v.

The stress resultant is a parameter which is considered to be characteristic of the state of stress at a point. The state of stress at any point is completely described by the normal stress σ_x, σ_y, σ_z, and by the shear stress τ_x, τ_y, and τ_z, in a tri-axial system with mutually perpendicular axes x, y and z or by the principal stress σ_1, σ_2, and σ_3 and their directions. The stress resultant may be calculated either by the shear stress hypothesis or the yield criterion.

According to the shear stress hypothesis, the stress resultant is

$$\sigma_v = \sigma_{max} - \sigma_{min}$$

According to the von Mises / Huber Hencky yield criterion the resultant stress is given by:

$$\sigma_y = \sqrt{\sigma_x^2 + \sigma_y^2 + \sigma_z^2 - \sigma_x\sigma_y - \sigma_y\sigma_z - \sigma_z\sigma_x + 3(\tau_x^2 + \tau_y^2 + \tau_z^2)}$$

In a bi-axial system;

$$\sigma_y = \sqrt{\sigma_x^2 + \sigma_y^2 - \sigma_x\sigma_y + 3\tau^2}$$

Allowable Stress

If the analysis is based on elasticity theory where all stresses are considered as primary stresses, the analysis may be carried out using characteristic values for the loads. In that case the maximum stress resultant shall not exceed the allowable stress.

The allowable stress is 0.72 $R_{t\,0.5}$ (θ)

Up to 60 °C	$R_{t\,0.5}$ (θ) = $R_{t\,0.5}$
Over 60 °C	$R_{t\,0.5}$ (θ) may be interpolated linearly between values at room temperature ($R_{t\,0.5}$) and the values for $R_{t\,0.5}$(θ) at 100 °C or 150 °C.

where $R_{t\,0.5}$ (θ) indicates the value of the minimum yield strength at temperature (θ).

Elasto-Plastic and Plastic Analysis

A more sophisticated analysis may be carried out using elasto-plastic or plastic analysis. The standard provides an Annex (Appendix) where the procedure to be followed, the relevant limit states, the contingency factors for the soil mechanics parameters, the load factors and stress concentration factors (for elasto-plastic analysis) are described.

The elasto-plastic and plastic analysis procedure is based on the method of (partial) load factors and calculation loads. The calculation loads are obtained by multiplying the relevant (characteristic) loads.

The load factors take into account the uncertainty for the magnitude of the loads, the strength of the material and the construction.

The effect of the calculation loads should not exceed the limit values associated with the relevant limit states.

Characteristic values for the loads (internal pressure, soil loads, differential settlement, thermal loads, etc.) are values for which the probability of their values being less than about 5%.

Characteristic values for the material properties of the pipeline (yield strength, tensile strength etc.) are values for which the probability of the actual values being less than the characteristic values is less than about 5%.

Characteristic values for soil engineering parameters are obtained by multiplying or dividing the average values by the contingency factors given in Table G.1 in the standard, reproduced below for convenience.

The characteristic loads then should be multiplied by the factors given in Table G.2 in the standard, reproduced below for convenience.

Table G.1
Contingency factors for soil engineering parameters referred to mean value

Parameter	**Factors**
Neutral earth pressure	1.1
Passive earth pressure	1.1
Lateral bending constant (k_l) - for sand and clay - for peat	 1.3 1.4
Ultimate bearing capacity - for sand and clay - for peat	 1.2 1.5
Horizontally passive earth pressure (contact angle $=180^o$) and horizontal neutral soil resistance (contact angle $=120^0$) - for sand - for clay - for peat	 1.2* 1.4 1.5
Soil friction	1.4
Relative displacement required for maximum soil friction (frictional elasticity)	1.4
Frictional bending constant (k_w)	1.7**
NOTES * These contingency factors are partly based on current pipelaying practice ** Soil friction (w) and displacement δ together give the frictional bending constant $k_w = w/\delta$ for which the contingency factor is 1.7.	

Table G.2
Loads, partial load factors

Load components	Load factors		
(Characteristic loads)	Operational phase		Construction phase
	Station	Pipeline	
Design pressure	1.50	1.39	1.10
Soil parameters	1.50	1.50	1.50
Traffic loads	1.50	1.50	1.50
Meteorological loads (wind, snow)	1.50	1.20	1.10
Marine loads (wave currents)	1.50	1.20	1.39
Incidental loads	1.50	1.39	1.10
Installation loads	1.50	1.50	1.10
Deadweight	1.50	1.50	1.10
Settlement / subsistence	1.50	1.50	1.10
Forced deformation	1.50	1.50	1.10
Temperature differences	1.25	1.25	1.25
Elastic bends	1.50	1.50	1.10

AS 2885.1 Australian Standard Pipelines – Gas and Liquid Petroleum

Australian Standard AS 2885.1 specifies requirements for the design and construction of steel pipelines and associated piping and components that are used to transmit single phase and multiphase hydrocarbon fluids, such as natural and manufactured gas, liquefied petroleum gas, natural gasoline, crude oil, natural gas liquids and liquid petroleum products. The standard applies when:

a) the temperatures of the fluid are not warmer than 200 ^{o}C nor colder than –30 ^{o}C; and
b) either the maximum allowable operating pressure (MAOP) of the pipeline is more than 1050 kPa, or at one or more positions in the pipeline the hoop stress exceeds 20% of the SMYS.

Wall Thickness for Design Internal Pressure (Clause 4.3.4.2)

The Australian pipeline standard gives the following wall thickness equation for the design internal pressure:

$$\delta_{dp} = \frac{p_d D}{2F_d \sigma_y}$$

where

δ_{dp}	=	wall thickness for internal design pressure, mm
p_d	=	design pressure, MPa
D	=	nominal outside diameter, mm
F_d	=	design factor
σ_y	=	yield stress, MPa

The required wall thickness is determined by the following equation:

$$\delta_w = \delta_{dp} + G$$

where

δ_w	=	required wall thickness, mm
δ_{dp}	=	wall thickness for design internal pressure, mm
G	=	allowance due to manufacturing tolerances, corrosion, erosion, threading, machining and other necessary conditions, mm.

Design Factor

The design factor (F_d) shall not be more than 0.72, except for the following for which the design factor shall not be more than 0.60:

(a) Fabricated assemblies.
(b) Any section of a telescoped pipeline for which the MAOP is based on a test pressure factor of less than 1.25.
(c) Pipelines on bridges or other structures.

Occasional Loads

Occasional loads are those which are unusual, or which occur with a very low or unpredictable frequency. Occasional loads include wind, flood, earthquake, and some traffic loads and surge pressure-induced load.

When occasional loads act in combination with other defined loads (excluding traffic or vehicular) the maximum limit may be increased to 110% of the stress limit allowed for the original load or load combination, unless a separate specific limit is defined for occasional loads. Occasional loads from two or more independent sources (such as wind and earthquake) need not be considered as acting simultaneously.

Axial Loads – Restrained Pipe

Whenever a pipeline or segment of a pipeline is of fixed length in service, it shall be considered to be restrained and stresses in service shall be calculated. Limit stresses shall be calculated in accordance with the maximum shear stress (Tresca) theory. Stresses from normal loads shall not exceed the following:

(1) Hoop stress ....Yield stress times design factor.
(2) Longitudinal stress ....Yield stress times design factor.
(3) Combined stress ....Yield stress times 0.90.

Strains from diametral deflections caused by normal loads or occasional loads shall not exceed 0.5%.

For pipe subject to bending stresses, the net longitudinal stress due to the combined effects of changes in temperature, imposed displacements and internal pressure shall be calculated from the equation:

$$\sigma_L = \mu\,\sigma_C - E\alpha(T_2 - T_1)$$

where

T_1	=	mean temperature of pipeline during hydrostatic testing, °C.
T_2	=	maximum or minimum operating temperature of pipeline, °C.
E	=	Young's Modulus, MPa
σ_L	=	longitudinal stress, MPa
σ_C	=	circumferential stress, MPa
α	=	linear coefficient of thermal expansion, $°K^{-1}$
μ	=	Poisson's ratio (0.3 for steel)

Axial Loads – Unrestrained Pipe

Whenever a pipeline or segment of a pipeline is not of fixed length in service, it shall be considered to be wholly or partially unrestrained and stresses, strains, deflections and displacements shall be assessed. The expansion stress range shall not exceed 72% of the yield strength. The expansion stress range, S_E, represents the variation in stress resulting from variations in temperature and associated imposed displacements. It is not a total stress.

Strains from diametral deflections caused by normal loads or occasional loads shall not exceed 0.5%.

Safety and Risk Assessment

The Australian standard contains a section on safety which is addressed through a formal risk assessment procedure. The risk assessment procedure is designed to ensure that each threat to a pipeline and each risk from loss of integrity of a pipeline are systematically identified and evaluated, while action to reduce threats and risks from loss of integrity is implemented so that risks are reduced to As Low As Reasonably Practical (ALARP). Further, the procedures are designed to ensure that identification of threats and risks from loss of integrity and their evaluation is an ongoing process over the life of the pipeline.

The risk assessment procedure consists of:

1) Risk identification
2) Risk evaluation
3) Management of risk

The risk identification step identifies the hazardous events through a location and location class analysis, a threat analysis which could result in hazardous events (such as external interference, corrosion, natural events, operations and maintenance activities), and an external interference protection design program, and a failure analysis that combines the design features of the pipeline with the identified threats to determine the failure mode.

The risk evaluation step contains a frequency and consequence analysis for each defined hazardous event. A frequency of occurrence of each hazardous event shall be assigned for each location where risk estimation is required. The frequency of occurrence shall be selected from

Table 2.4.2 in the standard. Table 2.4.2 is included in this report for convenience. The contribution of operations and maintenance practices and procedures to the occurrence of or prevention of hazardous events may be considered in assigning the frequency of occurrence to each hazardous event at each location.

For each hazardous event the consequence analysis assesses the consequences for:

(a) human injury or fatality;
(b) interruption to continuity of supply and economic impact; and
(c) environmental damage.

A risk matrix similar to Table 2.4.4(A) is used to combine the results of frequency analysis and consequence analysis. The severity classes used in the risk matrix are established for each pipeline project using severity classes. Table 2.4.4(B) provides typical severity classes for pipelines.

The management of risks addresses actions to be taken in order to reduce the risk when the derived risk parameters exceed regulatory requirements. Actions intended to reduce risk may be taken at the design stage or the operating pipeline stage. The actions to be taken for each risk class shall be in accordance with Table 2.5.1

The design stage actions may include the following:

a) Relocation of the pipeline route.
b) Modification of the design for any one or more of the following:
    i) Pipeline isolation.
    ii) External interference protection.
    iii) Corrosion.
    iv) Operation
c) Establishment of specific procedural measures for prevention of external interference.
d) Establishment of specific operation measures.

The operating stage actions may include one or more of the following:

a) Installation of modified physical external interference protection measures.
b) Modification of procedural external interference protection measures in operation.
c) Specific actions in relation to identified activities; e.g. presence of operating authority personnel during activities on the easement.
d) Modification to pipeline marking.

TABLE 2.4.2

FREQUENCY OF OCCURRENCE FOR HAZARDOUS EVENTS

Frequency of occurrence	Description
Frequent	Expected to occur typically once per year or more.
Occasional	Expected to occur several times in the life of the pipeline.
Unlikely	Not likely to occur within the life of the pipeline, but possible.
Remote	Very unlikely to occur within the life of the pipeline.
Improbable	Examples of this type of event have historically occurred, but not anticipated for the pipeline in this location.
Hypothetical	Theoretically possible, but has never occurred on a similar pipeline.

TABLE 2.4.4(A)

RISK MATRIX

Frequency of occurrence	Risk class			
	Severity class			
	Catastrophic	Major	Severe	Minor
Frequent	H	H	H	I
Occasional	H	H	I	L
Unlikely	H	H	L	L
Remote	H	I	L	L
Improbable	H	I	L	N
Hypothetical	I	L	N	N

LEGEND:
H = High risk
I = Intermediate risk
L = Low risk
N = Negligible

TABLE 2.4.4(B)

TYPICAL SEVERITY CLASSES FOR PIPELINES FOR USE IN RISK MATRIX

Severity class	Description
Catastrophic	Applicable only in location classes T1 and T2 where the number of humans within the range of influence of the pipeline would result in many fatalities.
Major	Event causes few fatalities or loss of continuity of supply or major environmental damage.
Severe	Event causes hospitalizing injuries or restriction of supply.
Minor	Event causes no injuries and no loss of or restriction of supply.

TABLE 2.5.1

RISK MANAGEMENT ACTIONS

Risk class	Action required
High	Modify the hazardous event, the frequency or the consequence to ensure the risk class is reduced to intermediate or lower.
Intermediate	Repeat the risk identification and risk evaluation processes to verify and, where possible to quantify, the risk estimation. Determine the accuracy and uncertainty of the estimation. Where the risk class is confirmed to be intermediate, modify the hazardous event, the frequency or the consequence to ensure the risk class is reduced to low or negligible.
Low	Determine the management plan for the hazardous event to prevent occurrence and to monitor changes which could affect the classification.
Negligible	Review at the next review interval.

CHAPTER 5

SUMMARY OF DESIGN MARGINS

This chapter contains a summary of design margins or safety factors of major pipeline and pressure vessel codes. This is used in the assessment of the design margins of existing codes and to develop the recommendations for changes to the design margins in B31.8 made in this report.

A summary of design factors on the yield strength and tensile strength margins is presented in Table 5.1.

Design factors (sometimes called factors of safety) are applied to the resistance capability of materials (strength) in order to provide a margin for uncertainties in the material, design, construction, operation of equipment and other factors.

Design factors summarized here are typically only used to address the most common mode of failure of bursting or plastic collapse due to internal design pressure. There are other modes of failure such as buckling, creep, cracking, fatigue, brittle low temperature fracture, expansion, thermal effects etc. that are addressed in codes. Such factors are not summarized in this report.

The design margins in the ASME B & PV Codes, several of the other ASME Piping Codes and the international pressure vessel codes take into consideration the complex configurations of many vessels and more types of loadings, such as thermal and cyclic stresses and areas of stress discontinuities. Transmission piping systems are "simpler" structures, which in most cases are not subject to the same complex design and loading issues as pressure vessels. The design factors in B31.8 are on the Specified Minimum Yield Stress (SMYS).

A summary of the methodologies used to determine the design margins for each of the piping codes is presented in Table 5.2.

Table 5.1 - Summary of Design Margins

	CODE	CONDITION	FACTOR[1] ON YIELD STRENGTH	FACTOR[1] ON TENSILE STRENGTH	COMMENTS
Transmission Pipeline Codes	B31.4 Pipeline Transportation Systems for Liquids	Pressure hoop stress	0.72		
	B31.8 Gas Transmission and Distribution Systems	Pressure hoop stress Location Class 1, Div 1 Location Class 1, Div 2 Location Class 2 Location Class 3 Location Class 4	 0.80 0.72 0.60 0.50 0.40		Code includes numerous modifications for types of facilities, crossings, encroachment, etc.
	British BS 8010 Section 2.8 Pipelines on Land: Steel for Oil and Gas	Pressure hoop stress Category B substances Category C & D Class 1 Category C & D Class 2 Category C & D Class 3	 0.72 0.72 0.30 0.30		Categories are related to hazard potential of substances and location class to population densities.
	Canadian CSA Z662 Oil and Gas Pipeline Systems	Pressure hoop stress Basic design factor Depending on location and type of facility	 0.80 0.50 to 0.80		Canadian code is similar to B31.8. Limit States Design (LSD) non-mandatory appendix
	Dutch NEN 3650 Requirements for Steel Pipeline Transportation	Pressure hoop stress Simplified analysis procedure	 0.55 to 0.72		Code is sophisticated with plastic, reliability, and probabilistic and complete risk analysis procedures.
	European DRAFT CEN PrEN 1594 Pipelines for Gas Transmission	Pressure hoop stress Basic design method Alternative design method	 0.67 0.67	 0.42 0.53	The alternative design route requires more controls. Has LSD option.
	German DIN 2470 Part 2: Steel Gas Pipelines	Pressure hoop stress	0.62 to 0.67		Variation is associated with material minimum elongation and fracture properties.

1 Factors presented as a multiple of S_y and S_u.

Table 5.1 - Summary of Design Margins (continued)

	CODE	CONDITION	FACTOR[1] ON YIELD STRENGTH	FACTOR[1] ON TENSILE STRENGTH	COMMENTS
Other Pipeline Codes	B31.1 Power Piping	Pressure hoop stress	0.67	0.25	
	B31.3 Process Piping	Pressure hoop stress	0.67	0.33	
	B31.5 Refrigeration Piping	Pressure hoop stress	0.625	0.25	
	B31.9 Building Systems Piping	Pressure hoop stress	0.67	0.25	
	B31.11 Slurry Transportation Systems	Pressure hoop stress	0.80		

1 Factors presented as a multiple of S_y and S_u.

Table 5.1 - Summary of Design Margins (continued)

	CODE	CONDITION	FACTOR[1] ON YIELD STRENGTH	FACTOR[1] ON TENSILE STRENGTH	COMMENTS
Boiler and Pressure Vessel Codes	Section I Power Boilers	Pressure hoop stress Prior to 1999 Addenda 1999 Addenda	 0.67 0.67	 0.25 0.285	Recently this Division reduced the margin on tensile from 4 to 3.5. First change since WW II.
	Section VIII Division 1 Pressure Vessels	Pressure hoop stress Prior to 1999 Addenda 1999 Addenda	 0.67 0.67	 0.25 0.285	Recently this Division reduced the margin on tensile from 4 to 3.5. First change since WW II.
	Section VIII Division 2 Alternative Rules for PVs	Pressure hoop stress i.e. primary general membrane stress	0.67	0.33	
	Section VIII Division 3 High Pressure Vessels	Pressure hoop stress i.e. primary general membrane stress	0.67 or 0.577		Factor 0.577 is based on fully plastic flow using maximum shear theory.
	British BS 5500 Unfired Pressure Vessels	Pressure hoop stress Carbon Steels Austenitic Steels	 0.67 0.67	 0.42 0.40	
	Dutch Stoomwezen Pressure Vessels	Pressure hoop stress Material with elongation > 10% Material with elongation < 3%	 0.67 ...	 0.44 0.25	Gas Limit State Design option
	German AD Merkblätt Pressure Vessels	Pressure hoop stress Rolled and forged steel and aluminum alloys Cast steels	 0.67 0.50		

1 Factors presented as a multiple of S_y and S_u.

Table 5.2 –Design Margin Determination

CODE	PLASTIC ANALYSIS	LIMIT STATE OR RELIABILITY	SOME RISK ASSESSMENT REQUIREMENTS	FULL RISK BASED REQUIREMENT
B31.1	NO	NO	NO	NO
B31.3	NO	NO	NO	NO
B31.4	NO	NO	NO	NO
B31.5	NO	NO	NO	NO
B31.8	NO	NO	NO	NO
B31.9	NO	NO	NO	NO
B31.11	NO	NO	NO	NO
AS 2885.1	NO	NO	YES	NO
BS 8010 – 2.8	NO	NO	YES	NO
CSA Z662	NO	YES	YES	NO
NEN 3650	YES	YES	YES	NO
PrEN 1594 DRAFT	YES	YES	YES	NO
DIN 2413 Part 1	YES	NO	NO	NO

References

1. ASME B31.1, Power Piping, ASME, New York, NY, 1998 Edition with addenda.

2. ASME B31.3, Process Piping, ASME, New York, NY, 1999 Edition with addenda.

3. ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids, ASME, New York, NY, 1998 Edition with Addenda.

4. ASME B31.8, Gas Transmission and Distribution Piping Systems, ASME, New York, NY, 1995 Edition with Addenda.

5. ASME Section VIII, Division 1, Rules for the Construction of Pressure Vessels, ASME, New York, NY, 1998 Edition with 1999 Addenda.

6. ASME Section VIII, Division 2, Alternative Rules for the Construction of Pressure Vessels, ASME, New York, NY, 1998 Edition with 1999 Addenda.

7. ASME Section VIII, Division 3, Alternative Rules for High Pressure Vessels, ASME, New York, NY, 1998 Edition with 1999 Addenda.

8. AS 2885.1, Australian Standard, Pipelines –Gas and Liquid Petroleum; Part 1 Design and Construction, Standard of Australia, Homebush, Australia, 1997.

9. BS 8010 Section 2.8, Code of Practice for Pipelines, Section 2.8 Steel for Oil and Gas, British Standard Institute, 1992.

10. CFR Part 192, Code of Federal Regulations, Pipeline Safety Regulations, U.S. Department of Transportation, October 1996.

11. CSA Z662-99, Oil and Gas Pipeline Systems, Canadian Standards Association, Etobicoke, Ontario, Canada, April 1999.

12. DIN 2413 Part 1, Design of Steel Pressure Pipes, German Standard, English Version by British Standards Institute, London, England, October 1993

13. DIN 2470 Part 2, Steel Gas Pipelines, German Standard, English Version by British Standards Institute, London, England, May 1983.

14. NEN 3650, Requirements for Steel Pipeline Transportation Systems, Dutch Standard, Nederlands Normalisatie-Instituut, 1st Edition, March 1998.

15. PrEN 1594, Pipelines for Gas Transmission, draft European Standard by Technical Committee CEN/TC 234, available from British Standards Institute, November 1994.

CHAPTER 6

CONCEPTS OF SAFETY FACTORS, DESIGN MARGINS AND RELIABILITY

Traditional Factor of Safety and Design Margin

When a component is subjected to a set of loads, Q, and the component has a capacity or resistance, R, then the concepts of safety factor and safety margin can be used to describe their relationship to reliability. The terms loads and resistance are used widely in structural and mechanical engineering, where the load is usually referred to as stress and the resistance as strength. In the traditional design approach, such as that adopted by the ASME Codes, the safety factor or safety margin is made large enough to more than compensate for uncertainties in the values of both the load and the resistance of the system. Although the load and resistance involve uncertainties, the design calculations are deterministic, using for the most part the best estimates of load or resistance. The probabilistic analysis of load and resistance can be used to estimate the reliability and also rationalize the determination and use of safety factors or design margins.

The safety factor or design margin is defined as

$$\nu = \frac{R}{Q} \qquad \textit{and} \qquad R = \nu Q$$

where

R = resistance (strength)
Q = load (applied stress)

and the safety margin or margin of safety is defined as

$$M = R - Q \quad \text{or} \quad M = (\nu\text{-}1)\,Q$$

Failure then occurs if the factor of safety is less than one **or** if the safety margin becomes negative. The concept of reliability comes from the notion that there is always some small probability of failure that decreases as the safety factor or safety margin increases.

If we define the failure probability as

$$p = P(Q > R)$$

then in this context the reliability is defined as the probability of non-failure or probability of success

$r = 1 - p$ or $r = 1 - P(R < Q)$

When the load and resistance are associated with probability distributions, the mean values of the load and the mean value of the resistance can be expressed as

$$Q_m = \int_{-\infty}^{\infty} x \, f_Q(x) \, dx$$

$$R_m = \int_{-\infty}^{\infty} x \, f_R(x) \, dx$$

Thus the traditional safety factor is associated with the mean or average quantities and is expressed as

$$\nu = \frac{R_m}{Q_m}$$

As a second alternative the factor of safety can be expressed as the most probable value Q_o and R_o at the load and resistance distribution. Then the safety factor becomes

$$\nu = \frac{R_o}{Q_o}$$

The above definitions are associated with loads and resistances, which can be characterized in terms of normal or lognormal distributions.

Reliability Based Design

In general the expression for reliability can be obtained by integrating the probability distributions for load and resistance. The complete expression for reliability is given by (adopted from Lewis, 1987) [3]

$$r = \int_0^{\infty} \left[\int_0^{x} f_Q(q) dq \right] f_R(x) dx$$

The failure probability also can be determined as follows

$p = 1 - r$

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or

$$p = \int_0^{\infty} \int_x^{\infty} f_Q(q)\,dq \; f_R(x)\,dx$$

Thus the failure probability is loosely associated with the overlap of the probability density function for the load and resistance in the sense that if there is no overlap, the failure probability is zero and r = 1.

A graphical interpretation of reliability is provided in the AISC Load and Resistance Factor Design Specification (LFRD) Specification (AISC 1986). This is illustrated in Figure 6.1. It can be seen that because the resistance, R, and load, Q, are random variables, there is some small probability that R may be less than Q, (R < Q). This is portrayed by the shaded area in this figure where the distribution curves crossing the upper diagram of Figure 6.1 (Merkle and Ellingwood, 1990).

An equivalent situation is expressed if the expression R < Q is divided by Q and the result is expressed logarithmically. This results in a single frequency distribution curve which combines the uncertainties for both Q and R. The probability of attaining a limit state (R< Q) is equal to the probability that ln(R/Q) < 0 and is represented by the shaded area in the lower diagram of Figure 1. The probability of failure may be decreased, or conversely the reliability increased, by moving the mean of ln(R/Q) to the right or by reducing the spread of the curve about the mean relative to the origin. A convenient way is to express the mean using the standard deviation of the curve as a unit of measure. Thus the mean of the curve can be expressed as (AISC 1986)[1]:

$$\left[\ln(R/Q)\right]_m = \beta\,\sigma_{\ln(R/Q)}$$

The factor β is called the "reliability index".

If the actual probability distribution function for ln(R/Q) is known then a complete probabilistic analysis can be performed. In actual practice only the means and standard deviations of the many variables that make resistance and load functions can be estimated. This information can be used to derive the following design condition

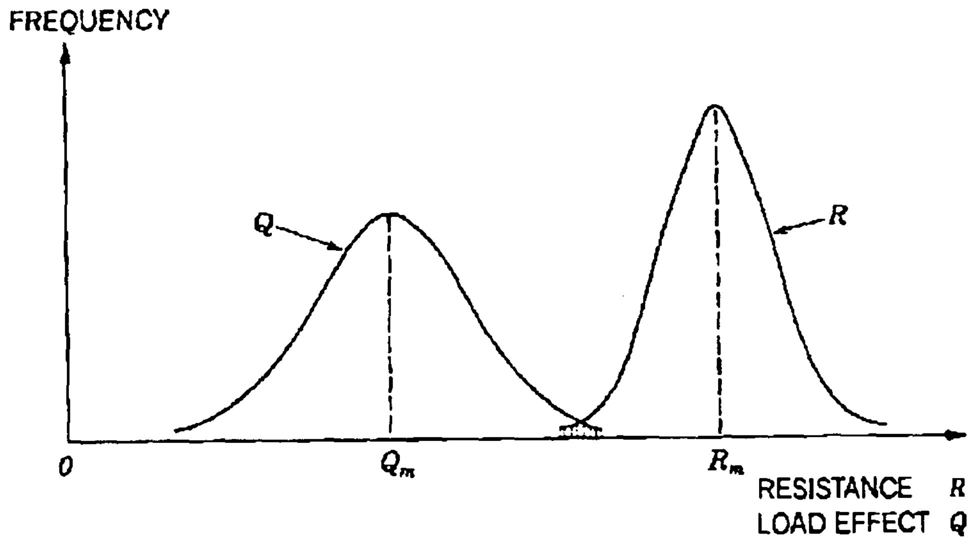
$$\beta\,\sigma_{\ln(R/Q)} \approx \beta\sqrt{V_R^{\,2} + V_Q^{\,2}} \le \lambda\nu\,(R/Q)_m \approx \ln(R_m/Q_m)$$

In the above formula, $V_R = \sigma_R/R_m$ and $V_Q = \sigma_Q/Q_m$, are the coefficients of variation for the resistance and load respectively. Similarly σ_R and σ_Q are the standard deviations and R_m and Q_m are the mean values.

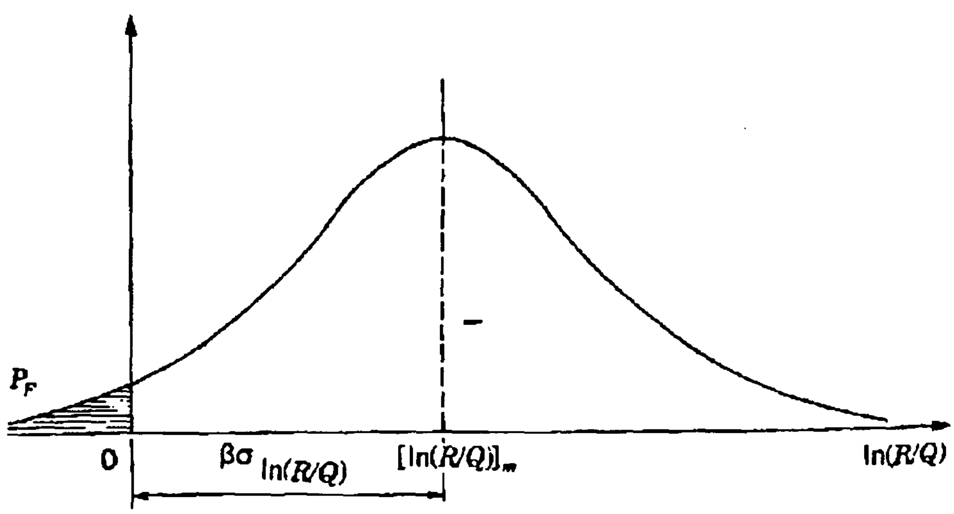
The above approximation provides a convenient way to calculate the reliability index, β, in terms of the means and coefficients of variations of the resistance and the load

$$\beta = \frac{\ln(R_m / Q_m)}{\sqrt{V_R^{\ 2} + V_Q^{\ 2}}}$$

The above concepts of reliability have been used in the development of the AISC LRFD (Load Resistance Factor Design). Similar applications can be adapted for ASME Code type applications.



Frequency distribution of load effect Q and resistance R



Definition of reliability index

Figure 6.1 Load, Resistance and Reliability Index Relationship (Ref. AISC LRFD Manual)

Example - Structural Reliability of Corroded Cylinder Subjected to Internal Pressure

The concepts of reliability can be used to obtain a probabilistic solution of a corroded cylinder subjected to internal pressure. In this case all essential variables, such as geometry, material properties, effects of corrosion etc., can be investigated in terms of their impact on safety. A literature search did not produce any available solutions to this problem. For the purposes of the present study the general solution for this problem is developed below. The probability and reliability concepts discussed previously are used in this development.

The margin of safety, M, or level of performance of the system, can be defined in terms of design variables vector, x, the resistance (strength or capacity), R, which is treated as a random constant, and the load or stress, Q, which is a function the random design variables. In mathematical terms this is expressed as

$$M(x) = M(x_1, x_2, x_3, \ldots\ldots, x_n) = R/Q$$

The limiting design condition or limit state may be defined as

$$M(x) = 0$$

Similarly the safe state may be defined as

$$M(x) \geq 0$$

and the failure state as

$$M(x) \leq 0$$

To get a complete description of the reliability of the system, the joint density function of M(x) needs to be known. Generally this is not the case, and an approximate solution is obtained from the knowledge of the moments of the random variables, i.e., mean, standard deviation, etc..

Given a random function f(x) the mean or the expectation is represented as

$$\mu_f = \Sigma\, [f(x)]$$

and the standard deviation as

$$\sigma_f^2 = \Sigma\, [f^2(x)] - \mu_f^2$$

Expanding the function in terms of Taylor's series about the mean and neglecting high order terms, the second order approximation to the mean is given by (Zibdeh, 1990)

$$\mu_f = f(\mu_1, \mu_2, \ldots\ldots, \mu_n) + \frac{1}{2}\sum_{j=1}^{n} \frac{\partial^2 f}{\partial x_i}\Big|_{\mu} \sigma_{xj}^{\;2}$$

and the standard deviation is

$$\sigma_f \approx \sum_{j=1}^{n} \frac{\partial^2 f}{\partial x_i}\Big|_{\mu} \sigma_{xj}^{\;2}$$

where σ_{xj} is the standard deviation of the design variable x_j and can be written as

$$\sigma_{xj} = V_j\, \mu_j$$

where V_j is the coefficient of variation of x_j.

The probability of failure is obtained by assuming appropriate forms for the distributions for the stress (load) as well as the strength (resistance).

For normally distributed stress and strength, the probability of failure is written as

$$p_f = \Phi\left(-\frac{\mu_R - \mu_Q}{\sqrt{\sigma_R^{\;2} + \sigma_Q^{\;2}}}\right)$$

where Φ is the normal probability function and the remaining quantities are associated with the mean and standard deviation and have been defined previously.

The reliability can be calculated from

$$r_f = 1 - p_f$$

For a lognormally distributed stress and strength, the probability of failure

$$p_f = \Phi\left(-\frac{\lambda_R - \lambda_Q}{\sqrt{\zeta_R^{\;2} + \zeta_Q^{\;2}}}\right)$$

where

$$\lambda_R = \ln \mu_R - \frac{1}{2}\zeta_R^{\;2}$$

$$\lambda_Q = \ln \mu_Q - \frac{1}{2}\zeta_Q^{\ 2}$$

$$\zeta_R = \ln(1 + V_R^{\ 2})$$

$$\zeta_Q = \ln(1 + V_Q^{\ 2})$$

Similarly the reliability for the lognormal distribution can be obtained from the relationship

$$r_f = 1 - p_f$$

The above expressions can be used to obtain numerical solutions of the probabilities of failure for any corroded component with a given design equation or analytical solution for the stress. It can be used to study the sensitivity of any design variable on the reliability of the system. What is required is an analytical expression of the function f(x), i.e the load function Q(x).

Section VIII, Division 1 (ASME B & PV Code) Pressure Design Equation

For example the load function, or the design stress equation in the circumferential direction for a shell subjected under internal pressure, in ASME Code, Section VIII, Division 1, Par. UG-27, can be written as

$$s = \frac{1}{E}\left[\frac{PR}{t-c} + kP\right]$$

Where

s	=	stress, in.
E	=	joint efficiency
P	=	internal pressure, psi
R	=	inside radius, in.
t	=	thickness, in.
c	=	corrosion allowance, in.
k	=	constant = 0.6

B31.8 Pressure Design Equation

It should be recognized that the various sections of the B31 Piping Code use a similar equation to that in Section VIII Division 1 . The above equation can be adopted to represent the B31 pressure design formulas. In particular, B31.8 uses the thin wall cylinder equation for the design equation which is equivalent to setting k=0 in the above equation. The B31.8 formula for design pressure for steel gas piping can be written as

$s = PD/2tE$

where

D = outside diameter = 2 x outside radius

Code design rules for pressure equipment put a limit on the stress, s, which is typically referred to as an allowable stress, S. The allowable stress, S, is determined typically from the material tensile and yield strength and applying an appropriate design factor or factor of safety.

$S = v F_I$

where
F_I = Tensile Strength (F_u) or Yield Strength (F_y)

Note: For > X70 pipe $F_y \approx F_u - 10$ ksi. F_y and F_u converge as you exceed X70 pipe (X80, X90, X100, etc.)

Design rules require the following condition to be satisfied

$S \leq s$

For the above formulation, the relative importance of each of the above design variables can be examined against the reliability or safety of the component. Nominal or average values of the quantities together with an estimate of the coefficients of variation are required. Alternatively, any quantity of interest can be treated as a variable and its effect over a range of values can be examined.

The mean and standard deviation of the hoop stress can be obtained from the above equations by taking the appropriate partial derivatives of the above formula for the hoop stress.

After lengthy mathematical manipulations the following mean value of the hoop stress (load) is obtained using the above design formula

$$\mu_Q = \frac{1}{E}\left(\frac{PR}{t-c} + kP\right) + \left(\frac{PR}{E^3(t-c)} + \frac{kP}{E^3}\right)\sigma_E^{\,2} + \left(\frac{PR}{E(t-c)^3}\right)\sigma_t^{\,2} + \left(\frac{PR}{E(t-c)^3}\right)\sigma_c^{\,2}$$

Similarly, the expression for the standard deviation for the hoop stress (load) is

$$\sigma_Q^{\,2} = \left(\frac{Q}{P}\right)^2 \sigma_P^{\,2} + \left(\frac{P}{E(t-c)}\right)^2 \sigma_R^{\,R} + \left(-\frac{PR}{E^2(t-c)} - \frac{kP}{E^2}\right) \sigma_E^{\,2} + \left(-\frac{PR}{E(t-c)^2}\right)^2 \sigma_t^{\,2} + \left(\frac{PR}{E(t-c)^2}\right) \sigma_c^{2}$$

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Knowing the mean and standard deviations, the reliability or probability for failure can be obtained for normal distribution. For other types of distributions similar closed formed solutions can be obtained. In cases where the variables have different distributions or for complex problems, Monte Carlo simulations can be used to obtain numerical rather than closed formed solutions

Numerical Example

The following numerical example is presented below to illustrate the above reliability principles. The example does not represent an actual pipeline situation or typical conditions, but it is presented here for the sole purpose of illustrating the concepts discussed above.

Design Information

A NPS 10" pipe schedule 40 is constructed with ASTM A 53 Grade ERW material. The design temperature is 250 ^{o}F. There is no corrosion allowance. The Specified Minimum Yield Strength (SMYS) of the material specification is 35,000 psi. The actual mean yield strength measured from a number of pipe samples is 40,000 psi and the coefficient of variation of the data is 0.07. The coefficient of variation of the pressure is 0.015, of the thickness is 0.04 and the diameter is 0.0015. The remaining variables are constant and not varied in this example. The design factor, F, for B31.8 applications is 0.8, which produces the highest allowable stress in any of the ASME codes. Determine the allowable design pressure and the reliability. Normal distributions are assumed for all probabilistic variables.

Solution

The complete design parameters and design pressure solution is summarized in Table 6.1. Using the B31.8 equation presented above, the design pressure is 1901 psi.

Figure 6.2 shows the probability distribution function of the yield strength and the applied stress. The distance between the mean values (peak values) is an indication of the safety margin or design factor. The broadness of the curve is an indication of the standard deviation or variation of the yield strength data and the applied stress. The area of the overlapping curve is associated with the probability of failure but in magnitude is not equal to the probability of failure. Figure 6.3 shows the cumulative distribution functions, which is another form of the probability distributions.

Figure 6.4 shows the histogram or probability distribution of the applied stress obtained by running Monte Carlo simulations. The mean value of the applied stress is 28,000 psi and the standard deviation is 1204 psi.

The probability of failure of this example is 4.12E-5 and the reliability is 0.99995876. It can be seen that the reliability is extremely high in this example even with the high design factor of 0.8.

This is typical because of the high design margins used in codes of construction. For lower design factors used in other class locations the reliability approaches 1. It should be noted that this example only addresses internal pressure and the overall reliability is affected by other load conditions and other construction and operation factors.

References

1. AISC (1986), AISC Load and Resistance Factor Design Specification for Structural Steel Buildings, American Institute of Steel Construction, First Edition, September 1, 1986.

2. Dai, Shu-Ho and Wang Ming-O (1992), Reliability Analysis in Engineering Applications, Van Nostrand Reinhold, New York.

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4. Merkle, D.H., and Ellingwood, B. (1990), LFRD Loads, Modern Steel Construction, July-August 1990, pp. 15.

5. Zibdeh, H.S., (1990), Reliability of Thermally Loaded Cylinders, Journal of Pressure Vessel Technology, Vol. 112, August 1990, pp. 303-308.

Table 6.1

EXAMPLE OF RELIABILITY ANALYSIS OF PIPE UNDER INTERNAL PRESSURE

Design pressure	P	1901 Psi
Design temperature	T	250 F
Material ASTM A 53 Grade B ERW		
Pipe is 10 NPS Schedule 40		
Yield Strength, psi	Fy	35,000 Psi
Design Factor	F	0.8
Nominal Outside Diameter	D	10.75 In
Longitudinal joint factor	E	1
Temperature derating factor	T	1
Corrosion	c	0 In
Nominal thickness	t	0.365 In
Outside radius	Ro	5.375 In
Inside radius	Ri	5.01 In
B31.8 Design Pressure (calculated)	P	1901 Psi
Constant	k	0
Mean Yield Strength	S	40,000 Psi
Coefficient of variation of Yield Strength	V_S	0.07
Standard deviation of yield strength	s_strength	2800 Psi
Coefficient of variation of Pressure	Vp	0.015
Standard deviation of pressure	s_p	28.52 Psi
Coefficient of variation of thickness	V_t	0.04
Standard deviation of thickness	s_t	0.0146 In
Coefficient of variation of diameter	V_D	0.0015
Standard deviation of diameter	s_D	0.016125 In
Calculated stress (B31.8)	stress	28000.00 Psi
Standard deviation of applied stress	s_applied	1204.00 Psi
Normal distribution variable	z	-4
Probability of failure	Pf	4.12E-05
Reliability	Rf	9.9995876E-01

PROBABILISTIC VARIABLES

Design pressure	P	1901 Psi
Thickness	t	0.365 In
Outside diameter	D	10.75 In
Calculated B31.8 stress	stress	28000 In

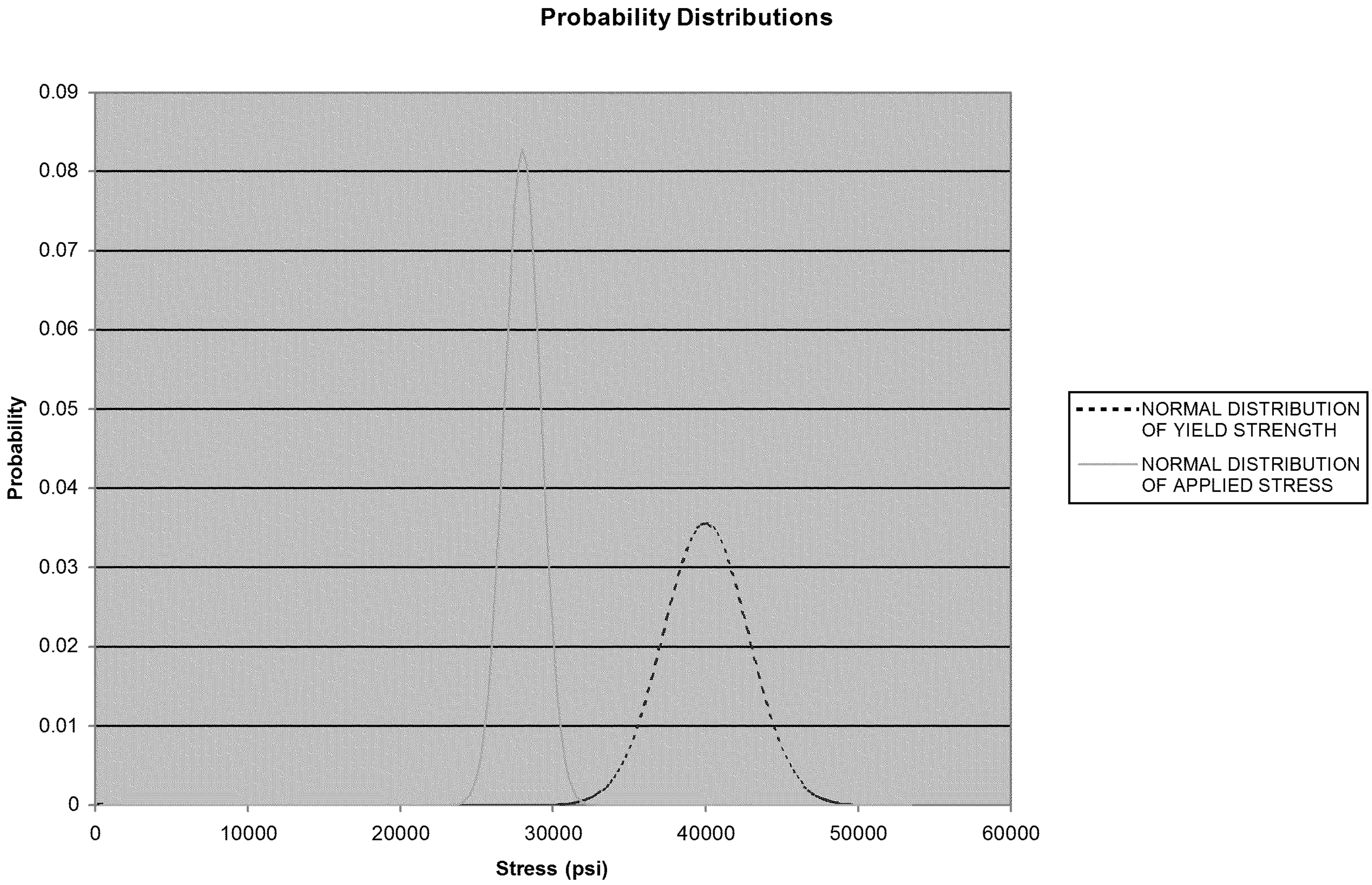

Figure 6.2 - Probability Distribution Function of the Yield Strength and the Applied Stress of Example

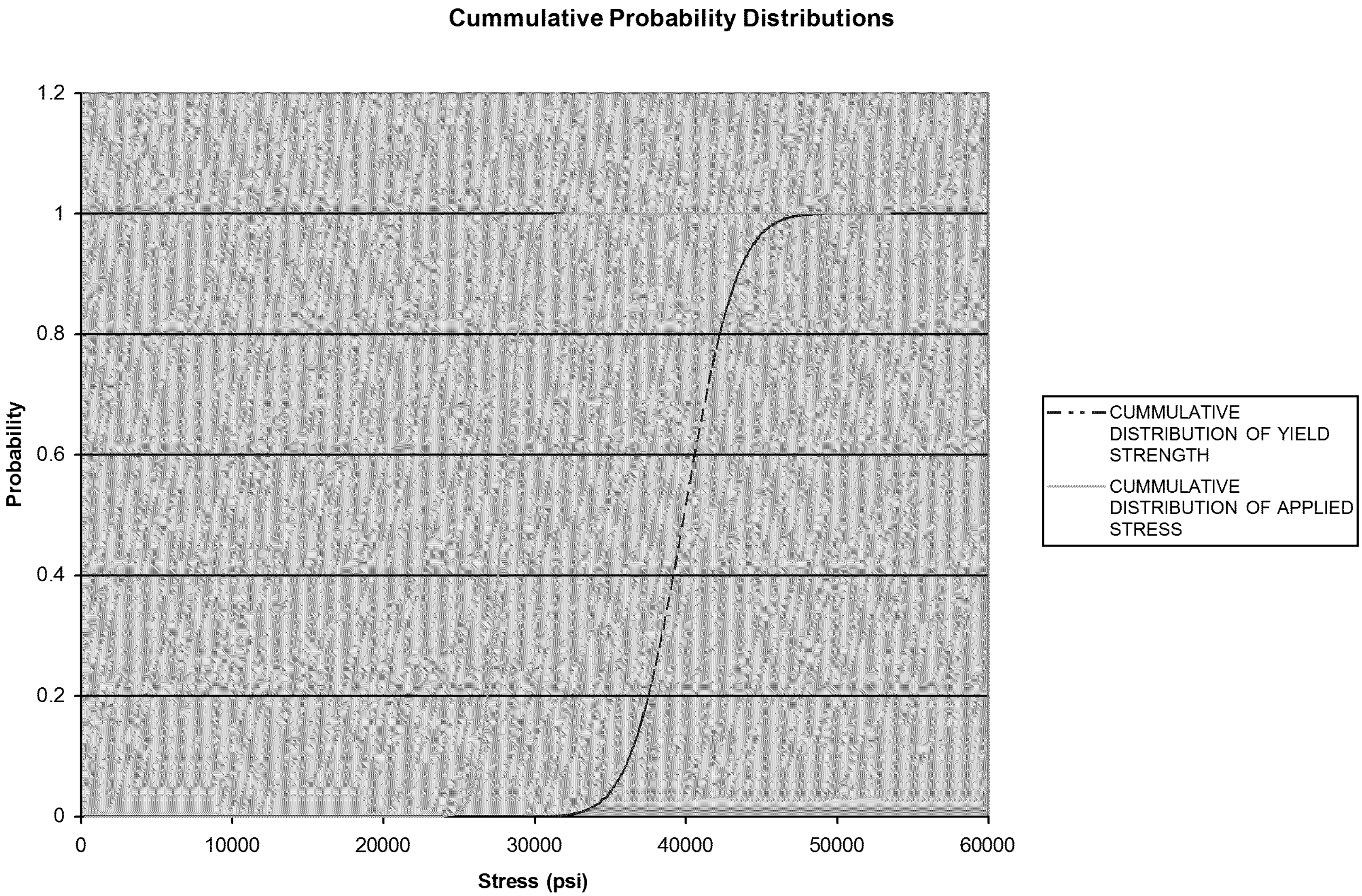

Figure 6.3 Cumulative Distributions of Example

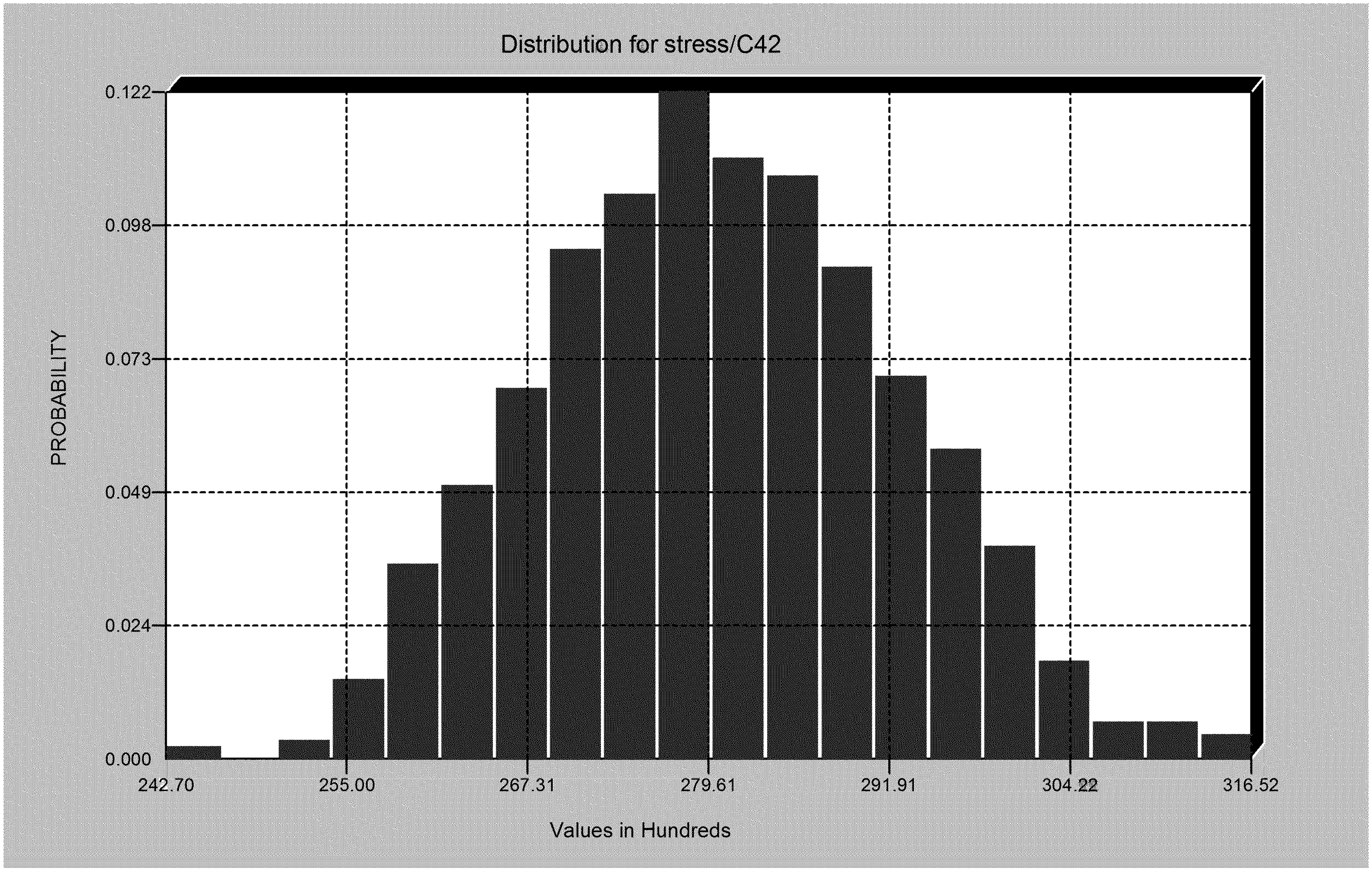

Figure 6.4 Probability Distribution of Applied Stress in Example

CHAPTER 7

RELIABILITY, PROBABILITY AND RISK METHODS

ASME pressure vessel, boiler and piping codes use the concept of the factor of safety in the development of design formulas. This approach began with the first ASME code in 1914, which addressed boilers, using a single factor as a particular mode of failure to provide an adequate protection against failure. Typically, separate factors are used for various modes of failure such a bursting, plastic deformation, plastic failure, buckling, creep, fatigue and other mode of failure that are considered significant for a particular application.

This single factor, also referred to as design margin, design factor or by other terms, is typically a conservative factor developed to address the various uncertainties in the quality of design, fabrication, examination, testing, material manufacture and handling, design analytical methods, applied loads, strength or resistance of the material and other factors that might affect the quality and performance of the pressure equipment.

The concepts presented in Chapter 6 are related to the development of reliability based design methods. These methods attempt to develop separate design factors to be applied to individual load or resistance terms. The objective is to provide a uniform design margin or factor of safety against the numerous load and resistance variables that are use to model a particular mode of failure.

In discussing risk based methods and to understand better the limitations of present codes it is useful to present the basic definitions of probability of failure, reliability and risk.

Risk

Risk is a term that accounts for both the probability of failure and the consequence of failure. In mathematical terms risk is expressed as :

Risk = probability x consequence

or

$$Q = P \times C$$

where

Q	=	risk
P	=	probability, frequency or likelihood of failure
C	=	consequence or severity of failure

The terms probability, frequency or likelihood of failure are used interchangeably and represent the same quantity. Typically the differentiation of these three terms is the method of quantification, i.e. a descriptive term (such as high, average, low, category A, B, etc), a single value estimate which is the frequency or number of failures in a given period or, a complete probabilistic description represented by a probability distribution function. The same applies to the terms consequence or severity. The consequences might involve, fatalities, injury or health implications to workers and the public, environmental damage or economic losses. When consequences involve fatalities, injury or health implications to people then the term safety is often used. The term factor of safety used in design codes is associated with the reduction or minimization of risk to humans.

Risk is synonymous with the expected consequences over a period of time. The term risk as used here should not be confused by common uses by the public at large. Often people use the term risk to refer to potential hazards, threats, events, perils or cause that might result in some risk. Examples are smoking, health, dietary, driving, natural events and other factors or causes. These factors might result in a probability of failure or a consequence of failure and thus some risk. Therefore, the public interchanges the terms risk and risk factors. In a strict sense, risk involves both the probability of failure and the consequence of failure in qualitative or quantitative terms.

Reliability

Reliability is a term associated with the probability that particular equipment will perform its intended function. Reliability is the complement of the probability of failure. Thus, reliability is related to the probability of failure by

$$R = 1 - P$$

where

R	=	reliability = probability of success
P	=	probability of failure

therefore, risk can be expressed as

$$Q = P \text{ x } C = (1\text{-}R) \text{ x } C$$

Risk Change, Benefit

The change in the risk is given by

$$dQ = dP \text{ x } C + P \text{ x } dC = -dR \text{ x } C + (1\text{-}R) \text{ x } dC$$

where, the letter d is used to indicate change or the derivative function. The change in the risk can be used reduce or minimize risk and compare against various decision alternatives. The commonly used term of benefit is the decrease (negative change) in risk. The risk cost is increase or positive change in risk. Mathematically, benefit and risk cost can be expressed as

$$B = dQ \quad \text{when } dQ < 0$$

$D = dQ \quad \text{when } dQ > 0$

where

B	=	benefit
D	=	risk cost

Benefit / Cost Analysis

Various decisions such as design and code requirements have an associated cost of implementation or investment to achieve a risk reduction. Traditional benefit/cost analysis can be used to rank, justify and select code requirements by calculating the benefit cost ratio, i.e.

$$\frac{B}{I} = \frac{dQ}{I} = \frac{benefit}{implementation\ Cost}$$

Uses of Risk Concepts in Existing Codes

There are numerous examples where risk concepts have been used indirectly in the development of existing codes over the years. The design rules in boiler, pressure vessel and piping codes can be related to the above risk concepts. Existing rules use the concept of the factor of safety (design margin or design factor) to provide an adequate margin of safety. ASME codes are commonly referred to as safety codes and are not performance codes. It can be seen that in terms of consequence they are concerned with safety, meaning the rules have been developed to avoid or minimize fatalities, injury or health implications to the public. Economic or other types of consequences are not considered directly, although Code Committee members in their decision-making and judgments sometimes consider such factors.

Neglecting differences in consequences or addressing only safety and not economic losses is equivalent to making all consequences to be the same. Thus, the consequence term in the risk change equation drops out. For a constant consequence, the change in risk is proportional to the change in the probability of failure or proportional to the change in the reliability, i.e.

$$dQ \sim dP \sim -dR$$

Therefore, ASME codes are simple conservative reliability based codes where a single design factor is used for all factors that affect a particular mode of failure.

Sometimes Code Committee members through judgments (not through rigorous risk analysis) have developed code rules that address varying consequences. Examples are the lethal service rules in Section VIII, Division 1 where more restrictive fabrication and examination requirements are stipulated. The increase in the allowable stress limits for wind and earthquake is a recognition of the reduced probability of occurrence of such unlikely events in relation to other design loads. Section III, the nuclear code differentiates its requirements in terms of class 1, class 2 and class 3 components. These components are obviously indirectly related in their importance to the potential consequence or severity of failure.

The B31.3 process piping code uses the fluid service classifications of normal service, category D and high pressure to address differences in consequences of failure. The increases in the allowable stresses for occasional loads , such as wind and earthquake loads, in comparison to sustained loads such as pressure and dead weight loads reflect the different probability of occurrence.

The ASME B31.8 is one of the most sophisticated ASME codes in its adoption of risk concepts. B31.8 has adopted location classifications to specify different design factors. Most ASME codes use the same design factor for a particular mode of failure. In B31.8, Class locations are defined in terms of population densities in a specified region along a pipeline. The main reasoning of B31.8 committee members in adopting class location was the recognition of the potential of damage to a pipeline as a function of the population density. This is associated with the probability of occurrence of an event which effects the probability of failure of the pipeline. Similarly, the population density also effects the severity or consequence if a failure occurs.

The civil engineering industry for many years has incorporated requirements in building codes that have different requirements for various types of facilities such as structures, homes, hospitals, fire stations etc.. Building codes developed by the American Institute of Steel Construction (AISC), the American Concrete Institute (ACI) , national codes such as UBC, BOCA etc, took a leading role in their development and incorporation of design rules based on rigorous reliability based methods. The main objective has been more economical designs with improved and consistent factors of safety to cover various types of load conditions and other uncertainties. All these codes do not address the consequences with the same mathematical rigor as they do for the reliability or probability of failure.

Recently a number of ASME code committees have been examining similar type of reliability-based requirements; commonly referred to as partial design factors, limit state analysis etc. Some foreign pipeline codes, such as the Canadian code have already codified such requirements. Some foreign codes such as the Canadian, Australian, British, European, Dutch etc. have incorporated various levels of risk-based concepts. However, none of the codes have as yet developed rigorous risk based design rules and requirements that treat the probability of failure and the consequence of failure with the same importance and rigor. From a risk point of view both are equal in importance since risk is equal to the probability of failure and consequence of failure.

It is recommended that B31.8 first undertake an effort to review in detail other foreign pipeline codes that have incorporated reliability and risk based concepts. However, it is strongly recommended that B31.8 take the lead in the development and implementation of code requirements that are based on complete risk based methods and not on reliability or quasi-risk based methods. This should result in improved safety and improved reliability, by reducing risk, increased design pressures, and more economical design, construction and operation of pipelines. In addition it will allow B31.8 to retain its leadership role among the international pipeline codes. The historic leadership of B31.8 is evident in reviewing the various foreign codes that are obviously based on the requirements and philosophy of B31.8. The incorporation of different design factors as a function of class location by B31.8 (a forerunner to reliability concepts) has influenced foreign codes to incorporate reliability or risk-based concepts.

CHAPTER 8

ASSESSMENT OF PRESENT PIPELINE CODE RULES

In this report a review of design factors in American and major international pipeline standards and codes was conducted. In addition, recent on going and planned changes in design margins in codes covering pressure vessels, boilers and piping have been examined and assessed.

The major design factors in the present B31.8 code such as the 0.72 factor, which is applied against the Specified Minimum Yield Strength for the design of internal pressure, first appear in the 1935 American Standards Association Code for Pressure Piping, ASA B31.1 for the cross-country pipeline rules. In the last 65 years major quality improvements have been made in all areas, which have significantly reduced the uncertainties covered by the design factors. Consequently changes in the design factors are overdue for economical operation, optimization of resources, to address international competition for the American pipeline industry while maintaining or still increasing the historical margins of safety and risk to the industry and the public.

The various foreign codes have basically adopted the B31.8 design factors but have made a number of refinements and improvements in their code rules. Major enhancements in foreign codes are associated with their incorporation of reliability based, limit state, plastic analysis and risk-based concepts.

Historically, design margins have been reduced to reflect technological improvements in all areas, such as fabrication, examination, testing, materials, welding, design, analytical methods, load characterization and specification, and many other factors that affect the quality of pressure equipment and safety performance. In the first ASME code adopted in 1914 that covered boilers, a design factor of 5 was applied to the tensile strength to establish the allowable tensile stress for internal pressure design. The same factor had also been adopted by the pressure vessel code and piping code developed in the 1920's. Reflecting the improvements in high strength materials, codes have also specified design factors on the yield strength as 5/8 or 2/3.

The dominant design factor of 5 against the tensile strength was reduced to 4 in the 1940's to reflect improvements in the technology. In the 60's and 70's a design factor of 3 was adopted in the Section III nuclear code for class 1 components, Section VIII, Division 2 of the pressure vessel code and B31.3, Process Piping, (formerly petroleum and refinery piping) based on improvements in the analytical techniques and other factors.

Recently the ASME undertook an effort to assess the design factors used in its boiler, pressure vessel, and nuclear component codes. This study was driven by international competition and current international standards, many of which employ lower design margins. Two major studies, References 1 and 2, have resulted in a reduction of the design margin from 4 to 3.5 in Section VIII, Division 1 of the pressure vessel code. Section I, Power Boilers, and Section III Class 2 & 3, Nuclear Components, soon followed and have also reduced the design margins from 4 to 3.5.

The same reduction is being considered by B31.1, Power Piping, which uses the same basic design margins as Section I.

By reducing the design factor from 4 to 3.5, ASME recognized that since its inception in the early 1900's, the Code has undergone major improvements and revisions as new and improved materials and methods of fabrication have been instituted in the pressure vessel industry over time. The allowable stresses used in the design formulae were determined by multiplying the ultimate tensile strength listed in the material specification by a factor, or design margin, set by the Code Committee. This factor was 5 until the 1940's when it was reduced to 4.

Other factors were also considered besides the ultimate tensile strength when determining the allowable stresses. For temperatures below the range where creep and stress rupture govern the stresses, the maximum allowable stresses are the lowest of the following:

1) 1/4 of the minimum tensile strength at room temperature;
2) 1/4 of the tensile strength at temperature;
3) 2/3 of the minimum yield strength at room temperature;
4) 2/3 of the yield strength at temperature.

With new toughness and design rules implemented in Division 1, improved material manufacturing processes and fabrication techniques, and successful experience with Division 2 vessels, which use higher stress values with similar toughness rules, the ASME B & PV Committee began researching the possibility of reducing the design margin to 3.5 on ultimate tensile strength. The Committee assigned the task to the Pressure Vessel Research Council (PVRC), which began researching the methods used to determine the allowable stresses and the existing Code rules for construction.

The PVRC investigated documented pressure vessel failures and determined that the majority of failures fell into one or more of the following categories:

1) Failures from design faults or inadequate details
2) Process or operation related failures of pressure vessels
3) Service related degradation
4) Poor notch toughness, material or fabrication defects, welding or repairs

The occurrence of failures in vessels due to inadequate design rules is very low. Most of these occurred during the hydrostatic test because the test medium temperature was too low. The research showed that the majority of failures that have been documented were related to poor notch toughness, normal service degradation and operating conditions. Recent revisions to the Code in the areas of notch toughness, fabrication and hydrostatic/pneumatic testing requirements were made to reinforce the existing requirements. The PVRC concluded, citing the advances in the Code and manufacturing capabilities, that the design margin could be justifiably reduced to 3.5 on the ultimate tensile strength at temperature below the creep range.

With the implementation of the 1999 Addenda to the 1998 Edition the maximum allowable stresses listed in Section II, Part D, Tables 1A and 1B have changed as a result of this design margin reduction.

Based on the recent changes on the design factor to ASME Section VIII, Division 1 and other codes that use the same design factors, it may be possible to improve the design factors used in B31.8 without reducing the historical safety built into the pipeline design. Design factors have been used historically to address uncertainties such as in the design and operating loads, material manufacture, fabrication of components, examination, testing, analytical techniques, modes of failure, failure causes and other quality related factors

The B31.8 design factors have not changed for many years and do not reflect the improvements in the technology in the design, manufacture and operation of pipelines. The same improvements discussed in References 1 and 2 may be applicable to pipelines.

It is recommended that the B31.8 Code Committee undertake a similar effort, to that of the ASME Boiler and Pressure Vessel Code Committee, to examine the improvements in materials and fabrication techniques. As a result of this comprehensive study it may be possible to improve the existing design factors in B31.8 comparable to the recent change of the design factor from 4 to 3.5 in Section I, Section III, Section VIII, Division 1. This results in an approximate increase of 4/3.5 or approximately 15% in the design pressure.

Since B31.8 specifies different design factors that vary from 0.4 to 0.8 depending on the class location an appropriate adjustment is required for each location class before the above increase is implemented. The maximum design factor is 0.8 for Location Class 1 Division 1 pipeline segments. A number of foreign codes use the same factor but none exceed this factor. In addition, the pipeline codes have specified design factors only on the yield strength and not on the tensile strength (due to the nature of the imposed loads). Table 8.1 summarizes the yield and tensile strength properties for all B31.8 pipeline materials.

The Department of Transportation (DOT) pipeline safety rules (CFR Part 192) impose a maximum limit of 0.72 on the design factor for its Class 1 pipelines. The DOT rules have not changed since the 1970's and do not reflect the 0.8 maximum design factor and the distinction of Division 1 and Division 2 of Class 1 locations adopted by B31.8. A number of foreign codes have successfully adopted and implemented the 0.8 design factor. With successful past experience domestically and internationally with the 0.8 design factor, it is recommended the pipeline industry work with the U.S. DOT to adopt the maximum limit of B31.8.

Consistent with the application of the 15% increase in the design pressure for Class 4 pipelines and the 0% increase in the Class 1, Division 1 pipelines, appropriate increases in other location classes have been developed. These are presented and summarized in the Conclusions and Recommendation Chapter of this report.

References

1. Upitis, E., and Mokhtarian, K. (1996) Evaluation of Design Margins for ASME Code, Section VIII, Division 1, Prepared for the Pressure Vessel Research Council, May 1996, Revision 1.

2. Upitis, E., Mokhtarian, K., (1997) Evaluation of Design Margins for ASME Code Section VIII, Divisions 1 and 2 – Phase 2 Studies, Prepared for the Pressure Vessel Research Council, PVRC Project No 97-2, October 1997.

Table 8.1 – Summary of B31.8 Material Stresses

Material Spec.	Grade	Type	SMYS (Fy)	SMTS (Fu)	Ratio of Fu to Fy
API 5L	A25	BW, ERW, S	25.0	45.0	1.80
API 5L	A	ERW, S, DSA	30.0	48.0	1.60
API 5L	B	ERW, S, DSA	35.0	60.0	1.71
API 5L	X42	ERW, S, DSA	42.0	60.0	1.43
API 5L	X46	ERW, S, DSA	46.0	63.0	1.37
API 5L	X52	ERW, S, DSA	52.0	66.0	1.27
API 5L	X56	ERW, S, DSA	56.0	71.0	1.27
API 5L	X60	ERW, S, DSA	60.0	75.0	1.25
API 5L	X65	ERW, S, DSA	65.0	77.0	1.18
API 5L	X70	ERW, S, DSA	70.0	82.0	1.17
API 5L	X80	ERW, S, DSA	80.0	90.0	1.13
ASTM A 53	Type F	BW	30.0	48.0	1.60
ASTM A 53	A	ERW, S	30.0	48.0	1.60
ASTM A 53	B	ERW, S	35.0	60.0	1.71
ASTM A 106	A	S	30.0	48.0	1.60
ASTM A 106	B	S	35.5	60.0	1.69
ASTM A 106	C	S	40.0	70.0	1.75
ASTM A 134	A283A	EFW	24.0	45.0	1.88
ASTM A 134	A283B		27.0	50.0	1.85
ASTM A 134	A283C		30.0	55.0	1.83
ASTM A 134	A283D		33.0	60.0	1.82
ASTM A 135	A	ERW	30.0	48.0	1.60
ASTM A 135	B	ERW	35.0	60.0	1.71
ASTM A 139	A	EFW	30.0	48.0	1.60
ASTM A 139	B	EFW	35.0	60.0	1.71
ASTM A 139	C	EFW	42.0	60.0	1.43
ASTM A 139	D	EFW	46.0	60.0	1.30
ASTM A 139	E	EFW	52.0	66.0	1.27
ASTM A 333	1	S, ERW	30.0	55.0	1.83
ASTM A 333	3	S, ERW	35.0	65.0	1.86
ASTM A 333	4	S	35.0	60.0	1.71
ASTM A 333	6	S, ERW	35.0	60.0	1.71
ASTM A 333	7	S, ERW	35.0	65.0	1.86
ASTM A 333	8	S, ERW	75.0	100.0	1.33
ASTM A 333	9	S, ERW	46.0	63.0	1.37
ASTM A 381	Class Y-35	DSA	35.0	60.0	1.71
ASTM A 381	Class Y-42	DSA	42.0	60.0	1.43
ASTM A 381	Class Y-46	DSA	46.0	63.0	1.37
ASTM A 381	Class Y-48	DSA	48.0	62.0	1.29
ASTM A 381	Class Y-50	DSA	50.0	64.0	1.28
ASTM A 381	Class Y-52	DSA	52.0	66.0	1.27
ASTM A 381	Class Y-56	DSA	56.0	71.0	1.27
ASTM A 381	Class Y-60	DSA	60.0	75.0	1.25
ASTM A 381	Class Y-65	DSA	65.0	77.0	1.18

CHAPTER 9

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

A review of design factors in American and major pipeline standards and codes from other countries was conducted. In addition, recent on going and planned changes in design margins in codes covering pressure vessels, boilers and piping have been examined and assessed.

Based on this review it has been concluded that it may be possible to improve the design factors used in B31.8 without reducing the historical safety built into the pipeline design. Design factors have been used historically to address uncertainties such as in the design and operating loads, material manufacture, fabrication of components, examination, testing, analytical techniques, modes of failure, failure causes and other quality related factors.

The major design factors in the present B31.8 Code, which are applied against the Specified Minimum Yield Strength for the design of internal pressure, first appear in the 1935 American Standards Association Code for Pressure Piping, ASA B31.1, in the cross-country pipeline rules. In the last 65 years major quality improvements have been made in all areas which have significantly reduced the uncertainties and the need for conservative design factors. Consequently, changes in the design factors are appropriate at this time. This will lead to more economical operation of pipelines, better optimization of resources, and will address international competition for the American pipeline industry, while preserving and improving upon the same historical margins of safety and risk to the industry and the public.

Recommendations

It is recommended that the B31.8 Code Committee begin an in-depth study of the current design practices used for pipelines in relation to the improvements in materials, design and fabrication techniques that have been made over the past several decades. Such a study could provide the technical justification to revise the design factors as presented in Table 9.1. The ASME Boiler and Pressure Vessel Code Committee has undertaken such a task in the past few years resulting in an improvement in the design margins for their respective Codes (Upitis and Mokhtarian, 1996 and 1997).

Table 9.1 summarizes the design factors that are recommended for consideration and adoption in the B31.8 and U.S. Department of Transportation design rules. Appropriate changes in the design factors in other areas of the code can be made consistent with the above recommendations.

A comparison of existing and recommended design factors is presented in Figure 9.1. The resulting ratio increases in the design factors are illustrated in Figure 9.2. The increases in the design pressures for B31.8 range from 0% to 15% depending on the class location. For DOT rules the increases range from 6% to 15% depending on the class location.

In addition, it is recommended that the B31.8 Code Committee undertake a major effort to fully incorporate risk-based principles in the code so that pipeline companies, which are now using risk management for their pipeline operations, can optimize the pipeline designs and improve safety margins as well. A number of pipeline standards from other countries have incorporated some aspects of reliability or risk-based principles. These are referenced in Chapter 4 of this report. In particular the Canadian, Australian, British and Dutch standards have incorporated risk based principles which B31.8 should consider as a minimum. Presently, various ASME Code Committees are assessing development of risk-based design codes under the names of partial safety factors, limit state design etc. However, presently all on-going efforts are in reality reliability based using concepts introduced in Chapters 7 and 8. They are similar to the AISC LRDF approach, which address only half of the risk term, namely the probability of failure or its complement, reliability. Some codes try to address consequences using various categories or classes to differentiate some requirements

It is also recommended that B31.8 take a leadership role towards developing a fully risk-based design approach where both the probability of failure and the consequence are treated with the same level of importance and mathematical rigor. Such an approach will lead to improved and consistent safety in pipelines, increased maximum allowable operating pressures, provide more economical designs and operations and overcome the limits imposed by the present single design factor approach where all uncertainties are combined into a conservative single design factor. In addition, it will bring back to B31.8 its recognized leadership in its international use by having the most advanced, sophisticated and economical design rules. The historical leadership of B31.8 is clearly evident in other foreign standards, which are based on past B31.8 design philosophy and rules. The incorporation of different design factors as a function of location class by B31.8 (a forerunner to reliability concepts) has influenced foreign codes to incorporate reliability or risk-based concepts.

In order to have the safest, best pipeline operations in the world, the B31.8 Code must make the best technical methods and the best design codes available to pipeline operators.

Table 9.1 Recommended Design Factors

CLASS LOCATION	EXISTING B31.8 DESIGN FACTOR	RECOMMENDED DESIGN FACTOR
Class 1, Division 1	0.80	0.80
Class 1, Division 2	0.72	0.76
Class 2	0.60	0.68
Class 3	0.50	0.57
Class 4	0.40	0.46

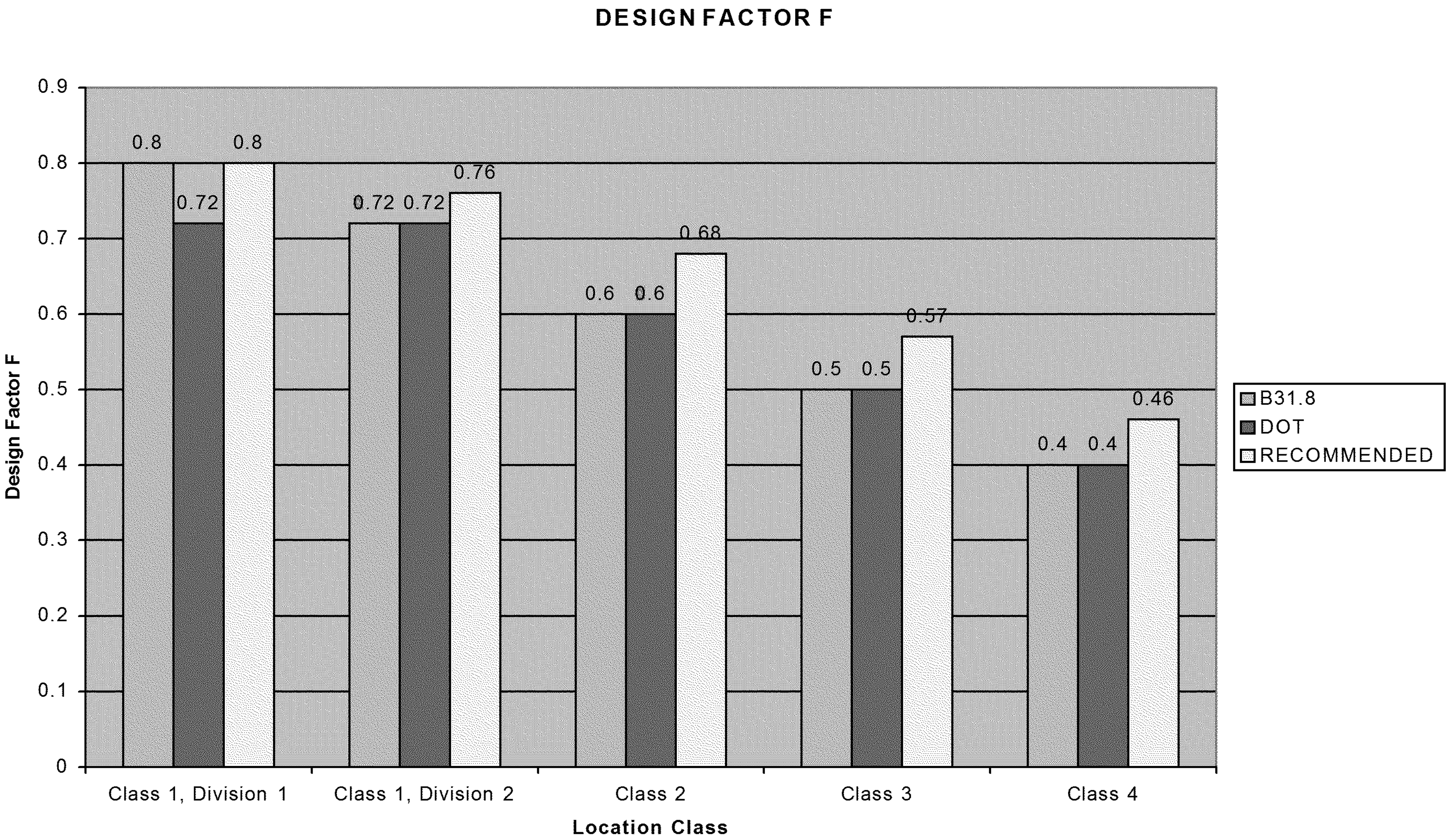

Figure 9.1 Comparison of Design Factors

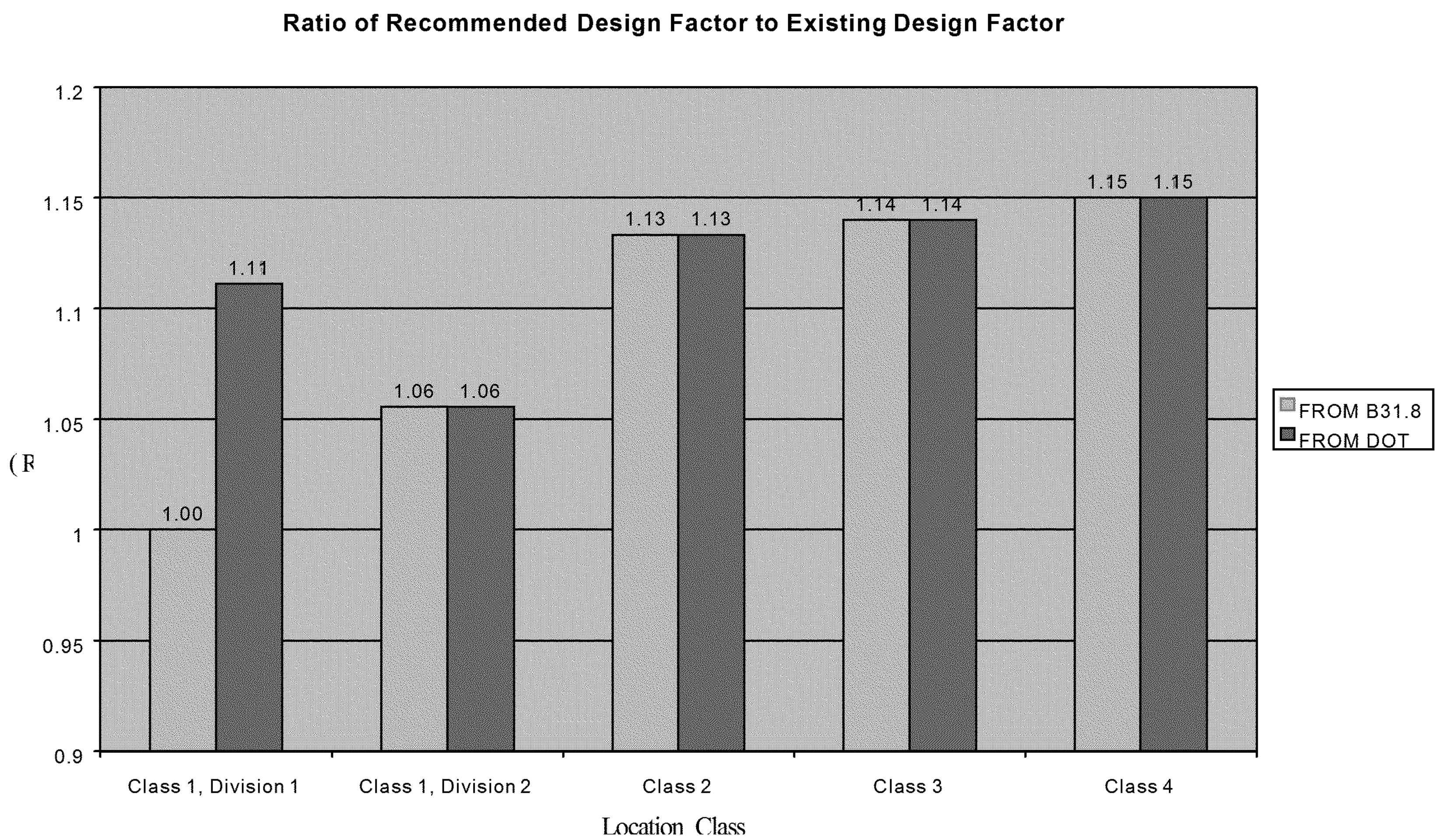

Figure 9.2 Recommended Design Pressure Increases

ATTACHMENT 15

Wesley B. McGehee, "Maximum Allowable Operating Pressure (MAOP) Background and History," prepared for Gas Research Institute, revised June 1998, page E-9.

APPENDIX E

MAOP BACKGROUND AND HISTORY

DRAFT

Report

on

MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP) BACKGROUND & HISTORY

March 5, 1998
(revised June/98 KGL)

For the

GAS RESEARCH INSTITUTE

By

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TABLE OF CONTENTS

MAXIMUM ALLOWABLE
OPERATING PRESSURE (MAOP)
BACKGROUND
&
HISTORY

INTRODUCTION

This report presents information on the background and history of MAOP extending back to the early American Standards Association for pressure piping (ASA B31.1) issued in the 1930's, and following the evolution of MAOP's in the piping codes on up to the present time. This will be done to the extent that information is available.

OBJECTIVE

The objective of this study was to present information in a manner that can be a basis for future developments in the formulation of other factors and criteria in setting MAOP's. Some background is presented to show how the ASME B31.8 Committee developed and adopted the 80 percent stress level within the Code.

APPROACH

In order to develop the background and history of the MAOP's presently in the ASME B31.8 Code for Gas Transmission and Distribution Piping Systems, I made an in- depth search of my own files, applicable literature, previous research, and my own experience within the ASME B31.8 Committee. The focus of this study was the origin of the 72 percent SMYS, class location safety factors, and the 80 percent SMYS.

BACKGROUND

The code for natural gas pipelines began in the U.S. as a part of the American Standards Association Code for Pressure Piping, ASA B31.1. This code was originally published in 1935 as an American Tentative Standard Code for Pressure Piping covering Power, Gas, Air, Oil and District Heating. Following the incorporation of Refrigeration to the scope, ASA B31.1 was published as the American Standard Code for Pressure Piping in 1942.

After this time there were additions and/or supplements published in 1944, 1947, and 1951. In all these publications the gas code was characterized under Section 2, Gas and Air Piping Systems. In 1952, the code was subdivided and the gas code became the Gas Transmission and Distribution Piping Systems Code, issued as ASA B31.1.8. This document incorporated material from Sections 2, 6 and 7 of the 1951 Edition of the Pressure Piping Code, making it a stand alone code.

In 1952 a new committee was organized to write code material for the new Section 8. This committee was chaired by Fred A. Hough (Ref. 1). The committee was charged to develop code material to reflect new materials and methods of construction and operations. This group made many changes including design philosophy for the class location concept. This material was incorporated and published in ASA B31.1.8 in 1955. In 1958 further revisions were published in ASA B31.8. Since that time the Section 8 Code Committee has published revisions in 1963, 1966, 1967, 1968, 1975, 1982, 1986, 1989, 1992, and 1995.

This report will show the concepts used to develop the Maximum Allowable Operating Pressures (MAOP's) for the various Editions of the Code.

HISTORY

Origin of 72 Percent of the SMYS

The appropriate MAOP for pipelines was one of the fundamental matters that had to be resolved. The committee needed to find some basis for establishing the MAOP for pipelines. Many operators felt that the MAOP should be based on a test pressure. The problem was that pipeline operators were utilizing a wide variety of field pressure tests. Some operators were testing pipelines to 5 or 10 psig over operating pressure. One reason for these relatively low test pressures was that testing was done with gas. In order to establish a consistent basis for MAOP, the committee agreed that the mill test pressure would be used and the rule would apply to all pipe. Customarily the mill test was 90 percent SMYS. The committee agreed that to be consistent, the MAOP for cross country pipelines should be 80 percent of the 90 percent SMYS mill test, which would be 72 percent of the SMYS. The 72 percent SMYS first appeared in 1935 in the American Standards Association Code for Pressure Piping, ASA B31.1.

The 1951 Edition of the B31.1 Code (ASA B31.1.8), for cross country pipelines, included the 72 percent SMYS (80% of 90% mill test) and provided an equation to define wall thickness based on this maximum pressure and nominal wall thickness. This code further identified a lower stress for pipe in compressor stations, which was limited to a percentage of the 80 percent of mill test as a function of diameter of the pipe diameter which was: 22% for 0.405 inch OD (OD = outside diameter and smaller pipe, 49% for 3.5 inch OD pipe, 72% for 8.625 inch OD pipe, and 90% for 24 inch OD and larger pipe. Therefore, for large diameter pipe in compressor stations, percent of SMYS allowed would have been 90% × 80% × 90% hence 65% of SMYS. The only other indication of limit on MAOP was 50 percent SMYS inside the boundaries of cities and villages.

As mentioned previously, the gas code was first issued as a stand alone code in 1952 in ASA B31.1.8 Gas Transmission and Distribution Piping Systems under a new committee chaired by Fred A. Hough (Ref. 2). This committee was charged with the responsibility of maintaining and updating the code. Over a two and one half year period, this Committee developed the ASA B31.1.8 - 1955 Gas Transmission and Distribution Piping Systems Code. During this time the MAOP was one of the items that was considered. Prior to this time the gas transmission code limited the MAOP to 72 percent SMYS in all locations except "inside incorporated limits of towns and cities" and certain limits in compressor stations. The MAOP in these areas were limited as indicated above.

Some in this committee felt that MAOP should be based on the field test. Hydrostatic test, with a water medium, was done by some operators to much higher pressures than had been done in the past. However, other operators continued to conduct field testing to the lower pressures. For this reason, basing the MAOP on field test pressure was unacceptable to these operators. The acceptable solution was finally found in adopting the long established practice of using 80 percent of 90 percent mill test pressure for MAOP in cross country pipelines.
There was a realization by this Committee that there was a need to consider intermediate levels of pipeline stress levels based on population density and other special conditions.

Establishing Stress Levels For Class Locations

In 1955, the second edition of the American Standard Code for Pressure Piping, Section 8. ASA B31.1.8 - 1955 Gas Transmission and Distribution Piping Systems was published. This document was the first to designate four types of construction to be used based on population density. Prior to 1955, code editions permitted a maximum operating hoop stress of 72 percent SMYS in all locations except those inside the incorporated limits of cities and towns. In these areas a maximum hoop stress of 50 percent SMYS was specified. Between 1952 and 1955 the Section 8 Subcommittee realized that there was a need to delimit areas of population density and establish hoop stress limits below 72 percent SMYS that would be appropriate in each area to protect public safety. Many operators were reducing the stress levels below 72 percent SMYS in certain areas although there were no code criteria to indicate which intermediate stress levels should be used for the various degrees of population density. These operators had adopted various lower stress levels for population density areas, as well as road and railroad crossings, but the criteria were not uniform among operators.

In order to study and evaluate how population densities could be classified and appropriate hoop stress levels could be established, the Section 8 Committee formed a subgroup to address this problem. The subgroup elected to use a ½ mile corridor with the pipeline as the centerline and to establish areas of population density within the corridor in running miles along the pipeline. An aerial survey of many miles of existing major pipelines was conducted to see what percentage of these pipelines would be impacted by areas of population density where lower stress levels should be applied to enhance public safety. A consulting engineering firm was engaged to evaluate the results. Reportedly, at the time of this study, it was found that about 5 percent of the total pipelines surveyed would be impacted by population density requiring stress levels below 72 percent SMYS. The subgroup determined that the population density in the ½ mile corridor traversed by the pipeline should be evaluated according to a building count along both 1 mile and 10 mile sections to establish a population index to define hoop stress levels to identify type of construction in each area. From this study, it was determined that class locations based on a population density index was needed as follows:

Class 1, (72% SMYS) Sparsely Populated Areas
Class 2, (60% SMYS) Moderately Developed Areas
Class 3, (50% SMYS) Developed Residential and Commercial
Class 4, (40% SMYS) Heavy Traffic and Multistory Buildings

In addition, types of construction were established as follows:

Type A (72% SMYS)
Type B (60% SMYS)
Type C (50% SMYS)

Type D (40% SMYS)

The type construction identified the hoop stress allowed in certain locations. For example uncased highways and railroad crossing in a Class 1 (72% SMYS) location would require a Type B (60% SMYS) construction in the crossing.

It is important to note that the ½ mile corridor width selected to establish the population index was not selected as one that would be a hazardous zone in the event of pipeline failure. The ½ mile corridor was one of convenience because the width of typical aerial photographs at that time were conducive for the purpose and could be used to evaluate nearby activities that may impact the pipeline safety in the future.

The reason population density is of concern near the pipeline is that the greater concentration of the public results in greater activity which may cause damage to the pipeline. Some of these activities are trenching for water and sewer lines, terracing, cutting for streets and other digging in the proximity of the pipeline. The lower stress levels are used so that in the event of limited outside damage to the pipeline from these activities, the pipeline may not fail causing a hazard to the public.

This defined ½ mile corridor width remained in the Code until the 1982 Edition of ASME B31.8, at which time the corridor was reduced ¼ mile because experience had shown that activity from population density over 1/8 mile from the pipeline would not cause damage to the pipeline. Also when pipeline failures occurred, impact on people or property was minimal beyond the 1/8 mile half corridor width.

The Federal Regulations (49 CFR 192) were issued in 1970 as a result of the Pipeline Safety Act of 1968, by the Office of Pipeline Safety (OPS). Although OPS adopted much of the 1968 Edition of ASME B31.8, they reduced the corridor width from ½ mile to ¼ mile. This was done in a Notice of Proposed Rule Making (NPRM) in which the following was stated (Ref. 3):

> "A recent study that included hundreds of miles of pipeline right-of-way areas indicated that a zone of this width is not necessary to reflect the environment of the pipeline. A ¼ mile wide zone extending one-eighth of a mile on either side of the pipeline appears to be equally appropriate for this purpose. It would be an unusual instance in which a population change more than one-eighth of a mile away would have an impact on the pipeline. Conversely, an accident on the pipeline would rarely have an effect on people or buildings that were more than an eighth of a mile away. For these reasons, it appears that the density zone can be reduced from one-half to one-quarter of a mile without any adverse effect on safety."

Development of 80% SMYS MAOP

In the early 1950's testing equipment, procedures and technology were developed to test pipelines with water, and some operators began hydrostatic testing. These operators were safely testing to higher pressures with water in contrast to earlier more risky testing with gas. Some operators readily recognized the value of hydrostatic testing as a new tool to prove the integrity of the pipeline. Some operators were hydrostatically testing to 100 percent of the actual minimum yield strength as determined by steel mill metallurgical test.

One operator determined the actual minimum yield strength by hydrostatic test from the pressure versus volume plot. The pressure-volume plot was made by starting the plot below the mill test pressure to establish a straight line (below initial deviation). The actual minimum yield strength was determined when the slope of the line became one-half of the slope of the straight line portion of the plot. By using actual minimum yield strength, MAOP's much greater than 72 percent SMYS were established. This allowed a means to establish a known safety factor between MAOP and test pressure allowing pipelines to be operated at 80 percent SMYS or greater. In addition, essentially all defects present during the test that may fail at MAOP were removed by testing to actual minimum yield.

After approximately 16 years of research, study and testing to prove the value of testing to actual minimum yield, the technology was documented and published in the AGA REPORT L 30050, 1968 (Ref. 4). Many in the pipeline industry realized the merits of hydrostatic testing to actual minimum yield to:

1. Increase the known safety margin between MAOP and test pressure;
2. Prove the feasibility of operating safely above 72 percent SMYS with a greater known safety factor;
3. Remove defects that might fail in service; and
4. Improve the integrity of the pipe.

Based on this experience, a proposal was made to ASME B31.8 to allow operation of pipelines above 72 percent SMYS around 1966 - 1967. Unfortunately the proposal to allow the operation of pipelines at 80% SMYS received some unresolved negative votes which precluded inclusion in the 1968 Edition of ASME B31.8 and before the B31.8 committee could resolve the issue and amend the code the Pipeline Safety Act of 1968 was enacted.

In 1968, the Office of Pipeline Safety (OPS) adopted the 1968 Edition of ASME B31.8 as an interim safety standard until 1970 at which time OPS issued the final rules as Title 49 Code of Federal Regulations Part 192 (49 CFR 192). When issued, Title 49 CFR 192 was almost verbatim from the 1968 Edition of ASME B31.8, hence, the MAOP in Class 1 locations for pipelines installed after November 11, 1970 became 72 percent SMYS. Those pipelines built before November 11, 1970 operating above 72 percent SMYS could continue operating at those pressures if they qualified under the "grandfather clause" in the Federal Regulations. The "grandfather clause" essentially said that not withstanding all other requirements for establishing MAOP for new pipeline that:

> "... an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976 ..." (Ref. 5)

This is subject to the requirements of change in class location.

The "Grandfather Clause" is for pipelines built before the Federal Regulations were issued. When a class location change occurs, that portion of the pipeline class location unit must meet the requirements of a new pipeline, i.e., pipelines under the "grandfather clause" which operate above 72 percent of SMYS would no longer be able to do so and no new pipelines constructed after the Federal Regulations were issued could be qualified above 72 percent SMYS.

After the Federal Regulations became effective, many operators failed to see a role for the ASME B31.8 in the regulatory environment. At this time the B31.8 committee essentially disbanded, however, in 1974 operators realized that unless code activities were resumed, pipeline technology would not advance beyond the 1968 Edition of ASME B31.8. It became apparent that unless the B31.8 code was maintained ASME would withdraw support and American manufacturers would be required to use foreign standards and specifications which might handicap them in the international arena. The B31,8 code is used in the Middle East, South America and many other international regions. In addition, American valve manufacturers and fabricators would be forced to build to foreign specifications in the absence of the ASME B31.8 Code which references U.S. specifications and standards. Consequently, the Code Committee met in 1974 and published the 1975 Edition to preserve the Code.

In the latter part of the 1970's, the proposal to allow pipelines to operate up to 80 percent SMYS was again submitted to the ASME B31.8 Code Committee. The Committee worked several years to develop criteria and requirements for the design, hydrostatic testing and ductile fracture control for pipelines to be operated up to 80 percent SMYS. The greatest opposition came from pipe manufacturing members of the Committee. The pipeline operator Committee members realized that transporting gas at 80 percent SMYS would be a great economic advantage, however, the pipe manufacturing members envisioned an economic loss in the sale of pipe. The use of an 80 percent SMYS greatly improves the utilization of pipe which would reduce the tonnage of pipe purchased. The Committee finally resolved all the issues involved in design, hydrostatic testing, and control of ductile fracture and approved provisions for pipelines to operate up to 80 percent SMYS. The allowance to operate pipelines to a maximum limit in onshore Class 1 locations was published in the ASME B31.8a - 1990 Addenda to the B31.8 - 1989 Edition.

CONCLUSIONS

The code for natural gas pipelines originated as an American Standards Association code for pressure piping. Committee members felt that the MAOP should be based on a pressure test, however, the operators were using a wide variety of field test pressures. In order to establish a consistent basis, the committee decided to use 80 percent of the 90 percent mill test, which was common to all qualified steel pipe. Thus, the MAOP for rural cross country pipelines was established as 72 percent SMYS and was published in the 1935 Edition of the American Standards Association Code for Pressure Piping, ASA B31.1.

The ASA B31.1.8 - 1955 Gas Transmission and Distribution Piping Systems was the first to designate class locations based on population density. Prior to this the previous code had allowed 72 percent SMYS for cross country pipelines and 50 percent SMYS for pipelines within the incorporated limits of towns and cities. The committee commissioned a study which indicated only 5 percent of the pipelines would require lower stress levels due to population density. The original corridor was set at ½ mile with the pipeline in the center line. The corridor was later reduced to ¼ mile in the ASME B31.8 - 1982 Edition. As a result of the study four stress levels were set, based upon increasing population density, which were defined as Class 1 (72% SMYS), Class 2 (60% SMYS), Class 3 (50% SMYS), and Class 4 (40% SMYS). Also four types of construction were identified to assign stress levels for fabrications, compressor stations, highway and railroad crossings in Class 1, Class 2, Class 3, and Class 4 locations.

Beginning in the early 1950's, hydrostatic testing was developing as a major tool to prove the integrity of the pipe. Some operators realized the value of testing pipe to actual minimum yield strength after many years of research and development, and some were using the actual minimum yield strength to determine MAOP. One operator actually used the determined actual SMYS to establish MAOP's in excess of 80 percent SMYS. Based on many years of research, testing and operational experience, the ASME B31.8 Committee developed code material for establishing an 80 percent SMYS MAOP. This provision was published in ASME B31.8a - 1990 Addenda to the B31.8 - 1989 Edition.

REFERENCES

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6. Hough, Fred A., "The New Gas Transmission and Distribution Piping Code," *Gas*, Part 5: Relating Design of Facilities to the Requirements of the Location, May 1955.

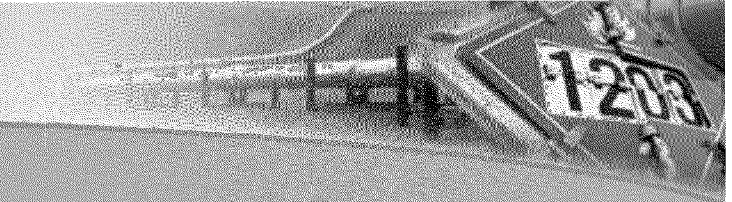
7. Hazardous Materials Regulation Board, "Establishment of Minimum Standards for Gas Pipeline Class Location Definitions," *Federal Register*, U.S. Department of Transportation, Title 49, Chapter 1, Parts 190 and 192, March 24, 1970, pp 5012-5014.

8. Duffy, A.R., et al, "Study of the Feasibility of Basing Natural Gas Pipeline Operating Pressure on Actual Yield as Determined by Hydrotest," A.G.A. Report L 30050, 1968.

9. Hazardous Materials Regulation Board, "Establishment of Minimum Standards," *Federal Register*, U.S. Department of Transportation, Title 49, Chapter 1, Parts 190 and 192, August 19, 1970.

ATTACHMENT 16

PHMSA Workshop presentation to Joint Technical Advisory Committee, "Managing Challenges with Pipeline Seam Welds and Improving Pipeline Risk Assessments and Recordkeeping," August 2, 2011, slide 11 showing gas line Pipe Seam Failures (2002-2010) by Seam Type including nine DSAW failures.



PHMSA Workshops

Managing Challenges with Pipeline Seam Welds
and
Improving Pipeline Risk Assessments and Recordkeeping

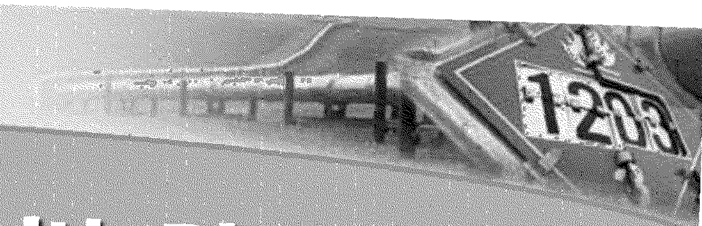
Jeff Gilliam
Director – Engineering and Research
8/02/2011

PHMSA Workshops

- **Managing Challenges with Pipeline Seam Welds –** Wednesday, July 21
- **Improving Pipeline Risk Assessments and Recordkeeping –** Thursday, July 22

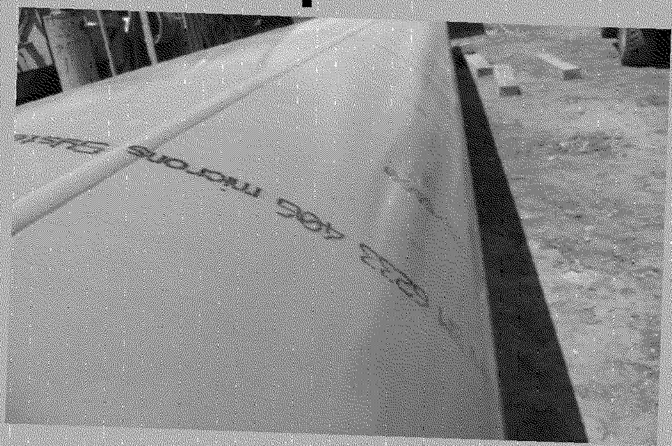
PHMSA Workshops

- **Over 250 attendees**
- **Representatives attended from:**
  - General Public
  - US/Canadian Federal Regulatory Agencies
  - State/Provincial Agencies
  - Standards Organizations
  - Pipeline Operators and Trade Organizations
  - Technology Vendors
  - Service Providers and Contractors
  - Steel Pipeline Manufacturers

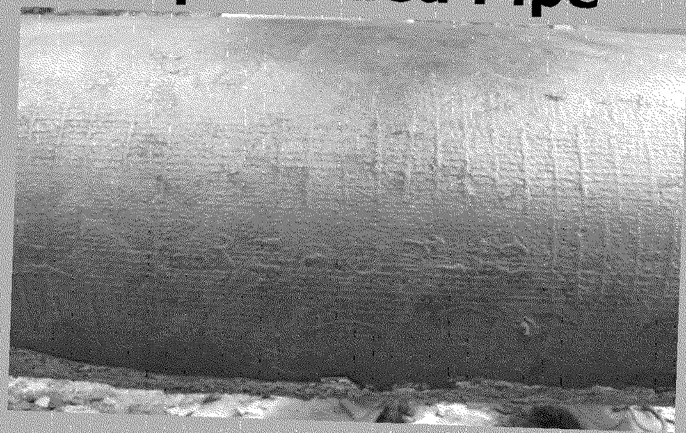


Managing Challenges with Pipeline Seam Welds

DSAW Pipe

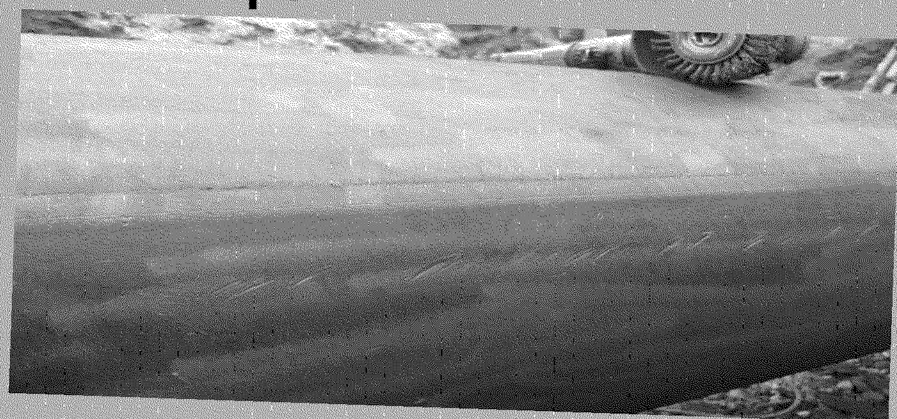


Lap Welded Pipe



Spiral Weld – SAW Pipe

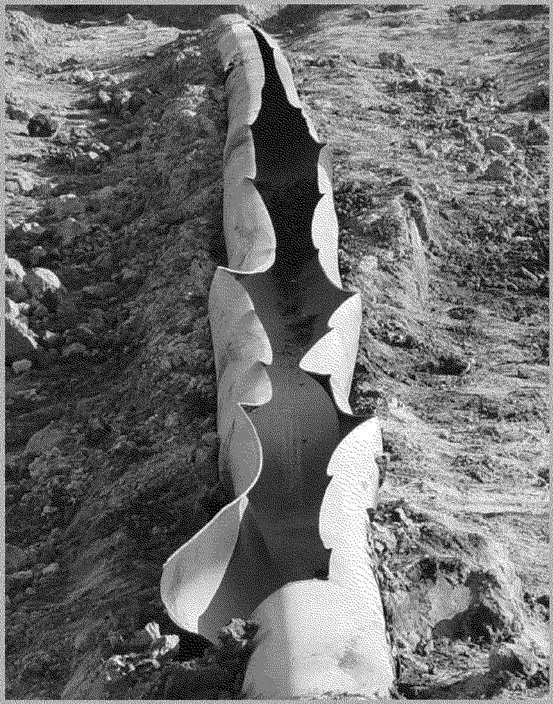
ERW Pipe



Pipe Seam - Failures

Submerged Arc Welded (SAW)

Pipe – ERW Seam



Electric Resistance Welded Pipe (ERW)

PHMSA Workshops – Pipe Seam Objectives

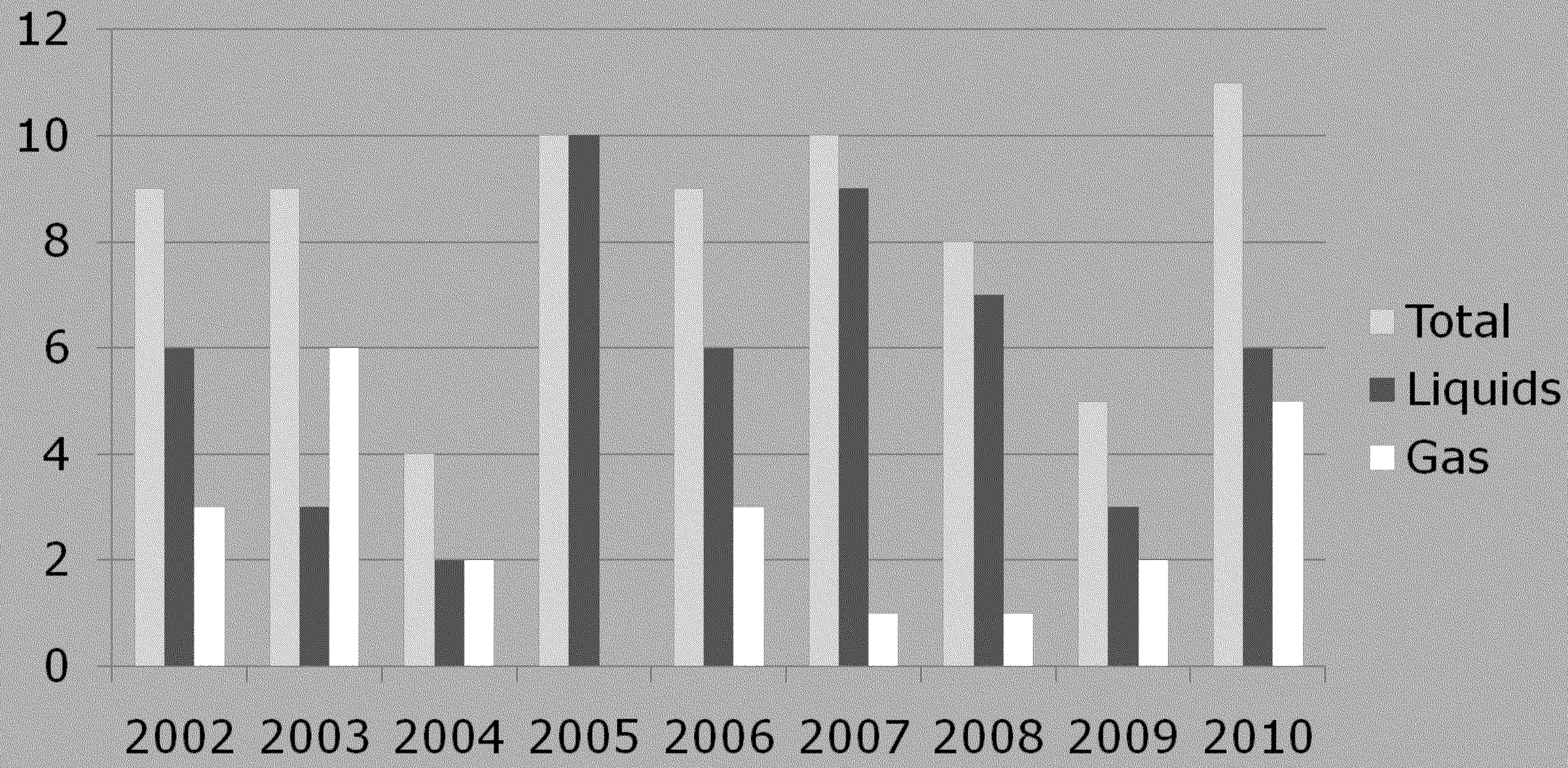
- **Presentations**
  - What is Nature/Extent of the Issue?
  - Identifying/Managing Seam Weld Challenges
  - Seam Weld Research Project
    - overview by Battelle, Brian Leis – PHMSA sponsored
  - Longitudinal Weld Seam Threat Analysis
    - how one operator is using existing technically to identify seam issues
  - Work Groups - recommendations
    - Information being summarized by PHMSA
    - Will help shape research and future policy

What are the Issues for Pipe Seams?

- **Seam weld integrity issues are:**
  - not always being identified by operator's integrity management and risk assessment approaches
- **Pipe that is not fit for service is:**
  - being left in service (some cases)and not being identified for special or urgent preventive and mitigative actions
- **Grandfather MAOP/MOP**
  - No Code pressure test to +125% MAOP/MOP

Pipe Seam Accident Experience

Pipe Seam - Accident/Incident Reports from 2002-2010



Past Accident History

- **Late 80s concern with LF-ERW**
  - PHMSA Technical Report 89-1, August 1989
    - 172 LF-ERW Failures in HL P/L 1968-1988
    - 103 ERW Seam Failures in Gas P/L 1970 – 1988
  - PHMSA Alert Notices ALN 88-01 & 89-01
- **Late 90s concern with managing integrity**
  - IMP rules including risk analysis
  - Special requirements for LF-ERW & Lap Welded pipe
- **Present**
  - Pipe seam integrity

Integrity Management Presumption of Seam Stability

- **Recent events cast doubt about underlying presumption of seam stability**
- **Long term pipe seam stability assurance practices for pipe seams (that have not been pressure tested to 125% MAOP/MOP) may not be sufficient:**
  - Records
  - Operational controls
  - Establishment of MAOP (for grandfathered pipe)
  - Excavation monitoring
  - External strain monitoring
  - Integrity Assessment
  - Interactive Threats – corrosion, SCC, selective seam corrosion, etc.
  - Criteria for Preventive and Mitigative Measures

Pipe Seams Failures (2002-2010)

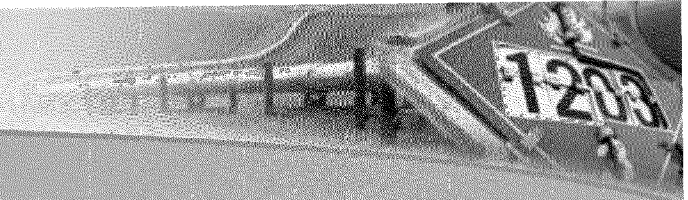
Seam Type	Gas	Hazardous Liquid	TOTAL	% of Total
DSAW	9	5	14	18
Flash Welded	1	5	6	8
HF ERW	2	14	16	22
LF ERW	5	21	26	35
Lap Weld	1	2	3	4
SAW	1	3	4	5
Other	4	2	6	8
Total	23	52	75	100

PHMSA Workshops – Pipe Seam Objectives

- **Pipeline Seam Welds - Objective**
  - Document the challenges with pipeline seam welds
  - Document constraints with managing and mitigating them
- **Some of the Workshop Findings**
  - Seam weld challenges exist
  - Over the past several decades major steps to remove seam weld issues have been taken
  - Hydrotesting is the preferred method to remove seam issues
  - Regulators and Standards Organizations have kept a focus on removing threats from seam welds
  - Most integrity efforts have been focused on LF-ERW pipe
- **PHMSA is reviewing take-away points from the Workshop**

Seam Integrity

- **Present and Future Seam Integrity issues:**
  - Process and tools to analyze seam integrity needs improvement
  - Better analysis of interacting threats that could destabilize a marginally stable seam
  - Process to obtain and integrate data relevant to seam integrity needs improvement
  - Actions when data is lacking or suspect
- **PHMSA future pipe seam assessment regulatory strategy will be based upon input for all sources including these Workshops**



Improving Pipeline Risk Assessments and Recordkeeping

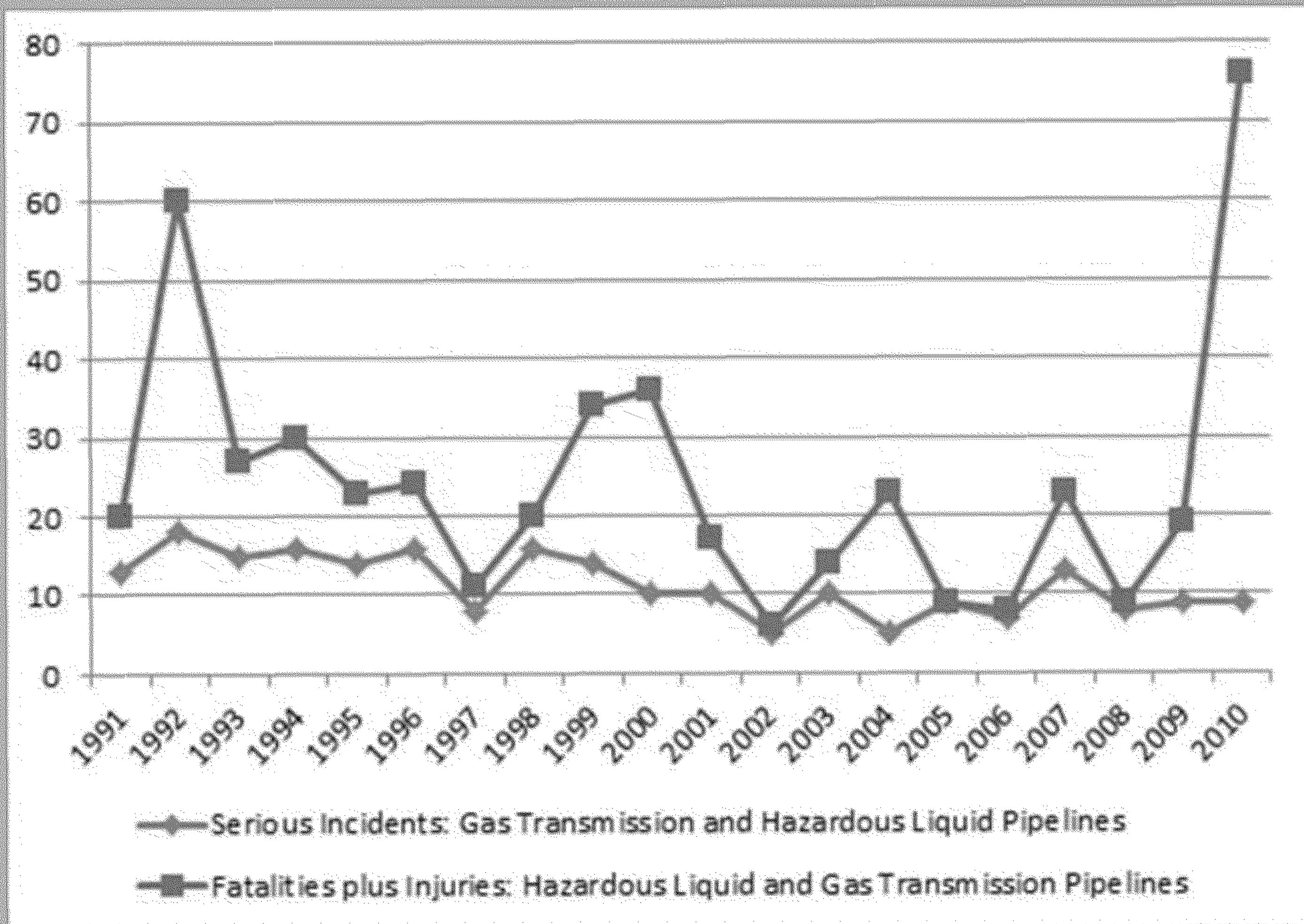
Improving Pipeline Risk Assessments and Recordkeeping

- **Panels**
  - Regulatory Perspective on Risk Assessments
  - Pipeline Operator Perspective on Risk Assessments
  - How Should Recordkeeping Gaps Influence Risk Assessments?
  - Indentifying Interactive Threats and Understanding Options

Integrity Management Rule Retrospective

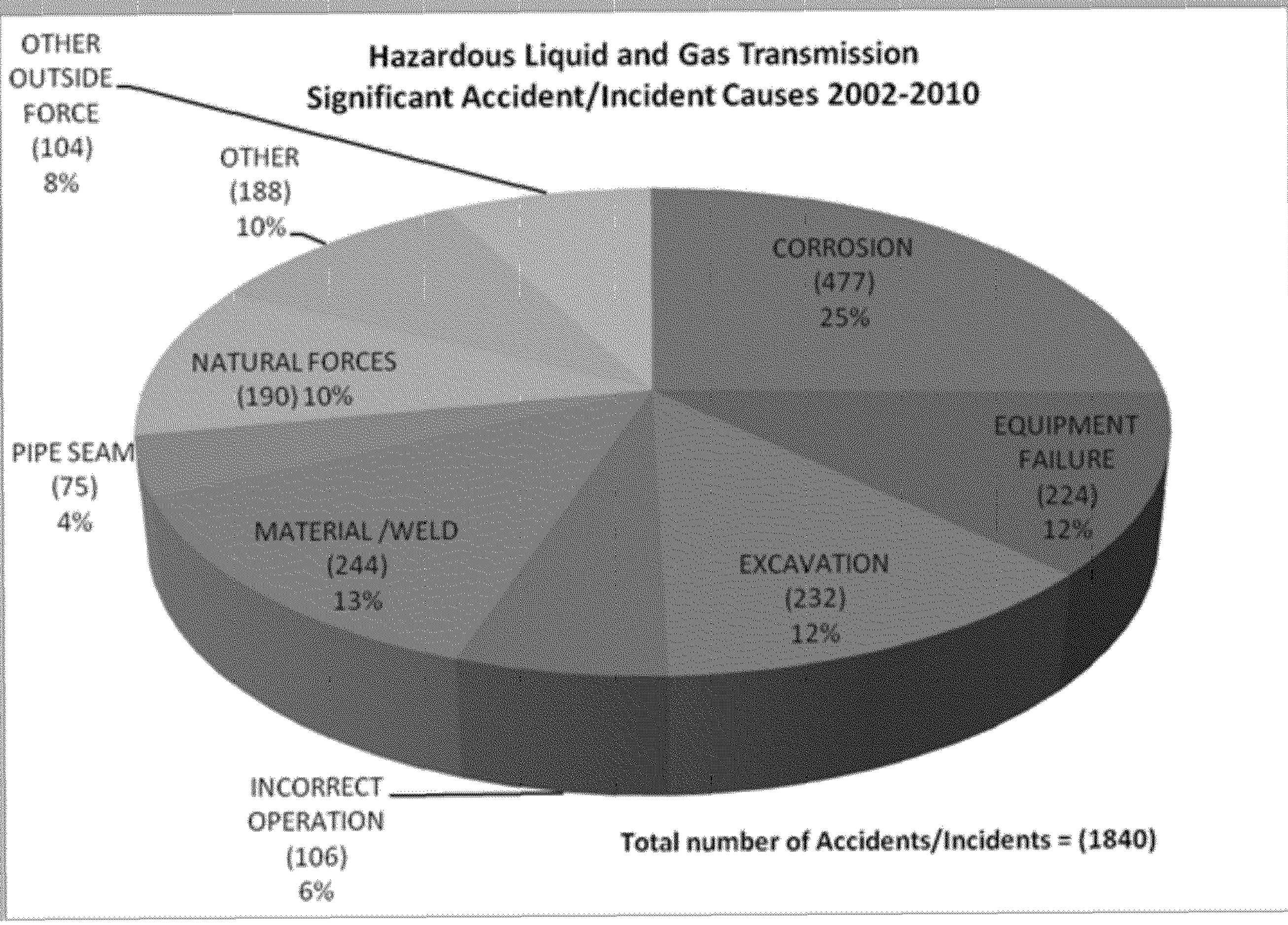
- **Need for accurate pipeline-specific risk assessment**
- **Underlying need for flexible regulations**
  - Enhance operator systems and processes
  - Identify, prevent, and mitigate risks and threats specific to each pipeline

Recent Events Illustrate Weaknesses in Risk Analysis



Interacting Threats

- **Multiple discreet threats that endanger pipeline integrity by simultaneously degrading pipe**



Integrity Management Rule

Success depends on OPERATOR

- Investigative
- Data-driven
- Analytical
- Integrity-related decision-making
- Prevention
- Mitigation

PHMSA Risk Assessment Concerns

- Weaknesses of Simple Relative Index Models
- Records (Availability and Quality of Data)
- Data Integration
- Interacting Threats
- Vintage/Legacy Pipe
- Connection to Real Decision-Making
- Uncertainties

Uncertainties

- **Subject matter expert opinion**
- **ILI tool accuracy/tolerance and reliability**
  - Tool tolerance, excavations, usage of unity plots
- **Hard-to-detect threats**
  - SCC, girth weld defects, long seam defects, equipment failure, manufacturing defects
- **Hydrostatic pressure test**
  - Future growth of un-remediated defects
- **Direct Assessment**
  - Heavy reliance in inferred conclusions
  - Conclusions based on minimal excavations

Data Gaps Panel Addresses

- Process to validate data
- Practices to deal with missing, incomplete, un-validated, or poor quality data
- Nature and urgency of response to data gaps
- Appropriate approaches for risk-based decision-making to account for uncertainties

Interactive Threats Panel Addresses

- Predictive modeling
- Effectively discovering interacting threats
- Improve risk analysis approaches
- Identifying interactive threats not addressed by common assessment methods (e.g., ILI, ECDA)
- Interacting threats not addressed by integrity assessment with current technology

Challenges to Success

- Data validation
- Response to missing or suspect data
- Risk analysis methods suitable to support effective integrity-related decision-making
- Identify effective preventive and mitigative (P&M) measures
- Rigorous processes

Summary

Historic opportunity to improve risk analysis

Challenges

- Data validation
- Response to missing or suspect data
- Deploy more sophisticated risk analysis methods
- Integrity-related decision-making
- Serious P&M measures
- Overall execution of integrity management

Thank You

ATTACHMENT 17

NTSB Report, Accident Report NTSB/PAR-95/01, "Pipeline Accid

Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fi

Jersey March 23, 1994," adopted January 18, 1995, p. 5.

NTSB/PAR-95/01 PB95-916501

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C. 20594

PIPELINE ACCIDENT REPORT

TEXAS EASTERN TRANSMISSION CORPORATION NATURAL GAS PIPELINE EXPLOSION AND FIRE EDISON, NEW JERSEY MARCH 23, 1994

Adopted: January 18, 1995

Notation 6362A

Injuries.--Table 1 categorizes the injuries sustained in this accident according to the International Civil Aviation Organization injury code.[5]

Table 1.--Reported injuries

Injury Type	Public	Other	Total
Fatal	0	0	0
Serious	2	0	2
Minor	100	10*	110
Total	102	10	112

* Firefighters

Medical and Pathological Information.--Emergency responders evacuated 29 apartment residents to area hospitals, where two individuals were admitted for treatment: one for a broken leg and one for smoke inhalation. Seventy-three apartment dwellers reportedly were treated for minor injuries by area hospitals or private physicians and released the same day. Most of the injuries sustained by residents were minor foot burns from the hot pavement and foot cuts from the glass shards of exploding car and apartment windows. No apartment resident suffered a fatal injury. However, a woman, who had a history of heart trouble, reportedly suffered a fatal heart attack while viewing the fire from her residence, which was about 1 mile from the site.

Pipeline Damage.--The rupture destroyed about 75 feet of pipe and released about 297 million standard cubic feet of natural gas.[6] Approximately 220 feet of pipe was ultimately replaced. Line 20 was out of service for 21 days. TETCO estimates that its cost of the lost gas and the pipe repairs will be about $2.5 million.

Other Damage.--Other parties reporting losses from the rupture, fire, and/or radiant heat included the following:

Buckeye Pipe Line Company (Buckeye) reported having to shut down and inspect two liquid pipelines located north of the railroad tracks at the asphalt plant to ensure that the lines had not been damaged by the heat from the fire. The two lines transported about 200,000 barrels per day of refined petroleum products. Buckeye estimated its loss at $94,000.

Consolidated Rail Corporation (Conrail) estimated the damage to its track from the fire and radiant heat was $250,000.

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[5] Title 49 *Code of Federal Regulations* (CFR) 830.2 defines *fatal injury* as "Any injury which results in death within 30 days of the accident" and *serious injury* as an injury that "(1) Requires hospitalization for more than 48 hours, commencing within 7 days from the date the injury was received; (2) results in a fracture of any bone (except simple fractures of fingers, toes, or nose); (3) causes severe hemorrhages, nerve, muscle, or tendon damage; (4) involves any internal organ; or (5) involves second or third degree burns, or any burn affecting more than 5 percent of the body surface."

[6] TETCO officials estimated the amount of gas lost would supply the needs of a 250,000- to 300,000-person community on an average winter day.