6.0 RATES, TOLLS AND CHARGES

6.1 ILLUSTRATIVE RATES, TOLLS AND CHARGES

NGTL provides in this section illustrative rates, tolls and charges for all services to demonstrate the relative rate impacts resulting from the proposed 2004 revenue requirement and forecasted contract demand and throughput quantities included in this Application. NGTL will separately apply in its 2004 GRA Phase 2 for approval of final rates, tolls and charges.

The illustrative rates have been calculated using the methodologies approved in the following decisions:

- Decision 2000-6 for the receipt-point-specific rate design;
- Decision 2002-044 for the CO_2 Management Service; and
- Decision 2003-051 for the rate design and service changes associated with the new FT-P service and modifications to FT-A and FCS services.

A Cost of Service Study prepared in 2003, attached as Appendix A, has been provided to illustrate the methodology used to determine the FT-A rate for 2004. All issues related to this study will be addressed in the 2004 GRA Phase 2.

Figure 6.1-1 provides an overview of the rate calculation process for 2004. Table 6.1-2 provides a comparison by service type between the 2004 illustrative rates and the 2003 final rates. The differences are primarily due to the increase in Revenue Requirement from $1,285.7 million in 2003 to ~~$1,349.2~~$1,355.8 million in 2004. Table 6.1-3 (including Attachments 1 and 2) contains the 2004 illustrative rates based on a January 1, 2004 implementation date.

Revised Figure 6.1-1 - 2004 Illustrative Rate Calculation

TOTAL REVENUE REQUIREMENT	$1,355.8 Million

MINUS

NON TRANSPORTATION REVENUE	$Million
FCS	$ 5.4
OS	$ 1.1
CO_2	$ 15.8
Total	$ 22.3

EQUALS

TRANSPORTATION REVENUE REQUIREMENT	$1,333.5 Million

MINUS

LRS REVENUE*	(Bcf/d)	($10^6m^3/d$)	$Million
LRS-1	0.66	18.67	$43.3
LRS-2	0.04	1.05	$ 0.8
LRS-3	0.05	1.41	$ 3.2
Total	0.75	21.13	$47.3

*Revenues adjusted to account for NGTL's contribution.

MINUS

OTHER TRANSPORTATION REVENUE

	(Bcf/d)	($10^6m^3/d$)	$Million
IT-D*	0.80	22.42	$ 59.1
STFT	0.00	0.00	$ 0.0
IT-R	2.22	62.69	$ 158.8
FT-P	0.33	9.24	$ 21.7
FT-RN	0.03	0.72	$ 1.1
FT-A	0.96	26.97	$ 6.4
Total	4.34	122.04	$ 247.1

*Revenues adjusted to account for Alternate Access.

EQUALS

FIRM TRANSPORTATION REVENUE REQUIREMENT	$1,039.1 Million

Revised Figure 6.1-1 cont'd. - 2004 Illustrative Rate Calculation

FIRM TRANSPORTATION REVENUE REQUIREMENT $1,039.1 Million

DIVIDED BY

CONTRACT DEMAND	(Bcf/)	(10^6m^3)
Delivery	2,786.48	78,506.3
Receipt	2,835.90	79,898.7
Total	5,622.38	158,405.0

EQUALS

FIRM TRANSPORTATION PRICE $0.1848/Mcf/d $6.560/$10^3m^3$/d

MULTIPLIED BY

RECEIPT CONTRACT DEMAND

2,835.90 Bcf 79,898.7 10^6m^3

EQUALS

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT

$524.1 Million

MULTIPLIED BY

DELIVERY CONTRACT DEMAND

2,786.48 Bcf 78,506.3 10^6m^3

EQUALS

FIRM TRANSPORTATION DELIVERY REVENUE REQUIREMENT

$515.0 Million

FIRM TRANSPORTATION RECEIPT REVENUE REQUIREMENT $524.1 Million

ALLOCATE TO EACH RECEIPT POINT

RECEIPT TRANSPORTATION REVENUE

	Revenue ($Millions)	volumes (Bcf/d)	(10^6m^3/d)	Average ($/Mcf/d)	Price ($/$10^3m^3$/d)
1 Year Receipt	$000.0	0.00	00.00	0.194	6.888
3 Year Receipt	$524.1	7.77	218.90	0.185	6.560
5 Year Receipt	$000.0	0.00	00.00	0.176	6.232
Firm Receipt	$524.1	7.77	218.90		
Floor Price				0.105	3.720
Ceiling Price				0.265	9.399

Revised Table 6.1-2

Comparison of 2003 Final and 2004 Illustrative Rates, Tolls and Charges

Service Type	Forecast 2004 Volume (10^6m^3)	2003 Final Rates ($/$10^3m^3$)	2004 Rates ($/$10^3m^3$)	Rate Variance [2003 - 2004] ($/$10^3m^3$)	Revenue Using 2003 Rates ($Millions)	Revenue Using 2004 Rates ($Millions)	Revenue Variance [2003 - 2004] ($Millions)
FT-R[1]	79,899	187.66	199.66	(12.00)	492.6	524.1	(31.5)
FT-D	78,506	183.11	199.66	(16.55)	472.3	515.0	(42.7)
FT-A[2]	9,844	0.57	0.65	(0.08)	5.6	6.4	(0.8)
FT-RN[3]	264	232.18	133.84	98.34	2.0	1.2	0.9
FT-P[2,3]	3,373	157.52	195.61	(38.08)	17.5	21.7	(4.2)
LRS[3]	6,816	189.35	193.14	(3.79)	42.4	43.3	(0.8)
LRS-2[4]	381	50,000/month	50,000/month	-	0.8	0.8	0.0
LRS-3[4]	515	184.76	188.71	(3.95)	3.1	3.3	(0.2)
STFT[3]	-	247.20	-	n/a	n/a	-	-
IT-R[3]	22,880	6.46	6.94	(0.48)	147.9	158.8	(10.9)
IT-D[6]	8,182	6.62	7.22	(0.60)	54.2	59.1	(4.9)
FCS	n/a	n/a	n/a	-	4.8	5.4	(0.6)
CO_2[3,5]	n/a	n/a	n/a	-	4.7	15.8	(11.1)
Other Service	n/a	n/a	n/a	-	0.9	1.1	(0.2)

Revenue Variance (Shortfall)[7]		(107.1)
Total Revenue Collected[7]	1355.8	
Revenue Requirement	1355.8	
Revenue Over Collection	0.0	

1 Rate quoted is a volume weighted average for a three year contract term and contract quantity is net of fuel
2 New rate methodology introducted in 2003.
3 Rate quoted is volume weighted average
4 Revenue quoted includes NGTL shareholder contribution
5 New service only forecasted for last three months of 2003. 2004 forecast is based on 2003 rates.
6 Forecast quantity is net of Alternate Access
7 Revenue numbers have more than the one significant digit that is reported (variance in total is due to rounding)

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Revised Table 6.1-3

2004 Illustrative Rates, Tolls and Charges

Service	**Rates, Tolls and Charges**
1. Rate Schedule FT-R	Refer to Attachment "1" for the applicable FT-R Demand Rate per month and Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $199.66/10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for the applicable FT-RN Demand Rate per month and Surcharge for each Receipt Point
3. Rate Schedule FT-D	FT-D Demand Rate per month $199.66/10^3m^3$
4. Rate Schedule STFT	STFT Bid Price Minimum bid of 135% of FT-D Demand Rate
5. Rate Schedule FT-A	FT-A Commodity Rate $0.65/10^3m^3$
6. Rate Schedule FT-P	Refer to Attachment "2" for the applicable FT-P Demand Rate per month.
7. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/10^3m^3/day) 1-5 years 9.31 6-10 years 7.78 15 years 6.98 20 years 6.20
8. Rate Schedule LRS-2	LRS-2 Rate per month $50,000
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month $188.71/10^3m^3$
10. Rate Schedule IT-R	Refer to Attachment "1" for the applicable IT-R Rate and Surcharge for each Receipt Point
11. Rate Schedule IT-D	IT-D Rate $7.22/10^3m^3$
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service

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	Schedule No.	Charge	
13. Rate Schedule OS	2003-00452-2	$83,333.00	/ month
	2003-03435-9	$899.00	/ month
	2003-03734-7	$698.00	/ month
	2003-058091-2	$2,568.00	/ month
	2003-03624-9	$27.00	/ month
	2003-07178-3	$150.00	/ month
	2003-07179-5	$1,391.00	/ month
	2003-07113-5	$8.00	/ month
	2003-05812-6	$118.00	/ month
	2003-05809-6	$163.00	/ month
	2003-03747-9	$1,707.00	/ month

	Tier	CO_2 Rate ($/10^{3}m^3)
14. Rate Schedule CO_2	1	532.41
	2	425.92
	3	283.95

Revised Table 6.1-3 Attachment 1

Receipt Point Number	Receipt Point Name	FT-R Demand Rate per Month ($\$/10^3m^3$)	FT-RN Demand Rate per Month ($\$/10^3m^3$)	IT-R Rate per Day ($\$/10^3m^3$)
1699	12 MILE COULEE	145.92	160.51	5.51
1337	ABEE	286.09	314.70	10.81
1631	ACADIA EAST	132.03	145.23	4.99
1613	ACADIA NORTH	132.69	145.96	5.01
1424	ACADIA VALLEY	185.90	204.49	7.02
3880	AECO INTERCONNECTION	113.23	124.55	4.28
1526	AKUINU RIVER	286.09	314.70	10.81
1681	AKUINU RIVER W.	286.09	314.70	10.81
1800	AKUINU RVR W.#2	286.09	314.70	10.81
2000	ALBERTA-B.C. BDR (CHART ACCOUNTING)	113.23	124.55	4.28
3868	ALBERTA-MONTANA BORDER INTERCONNECT	124.61	137.07	4.71
2291	ALDER FLATS #2	113.23	124.55	4.28
2200	ALDER FLATS S.	113.23	124.55	4.28
1075	ALDERSON	113.23	124.55	4.28
1208	ALDERSON NORTH	113.23	124.55	4.28
1103	ALDERSON SOUTH	113.23	124.55	4.28
5026	ALGAR LAKE	286.09	314.70	10.81
1851	AMISK SOUTH	263.72	290.09	9.96
1469	ANDREW	189.90	208.89	7.17
1573	ANSELL	150.19	165.21	5.67
2136	ANTE CREEK S.	286.09	314.70	10.81
1567	ARMENA	286.09	314.70	10.81
1770	ARMSTRONG LAKE	286.09	314.70	10.81
2708	ASSUMPTION	286.09	314.70	10.81
2734	ASSUMPTION #2	286.09	314.70	10.81
1326	ATHABASCA	283.22	311.54	10.70
1368	ATHABASCA EAST	271.84	299.02	10.27
1009	ATLEE-BUFFALO	113.23	124.55	4.28
1116	ATLEE-BUFFALO E	113.23	124.55	4.28
1098	ATLEE-BUFFALO S	113.23	124.55	4.28

1297	ATMORE	251.21	276.33	9.49
3858	ATMORE INTERCONNECTION	251.21	276.33	9.49
1792	ATUSIS CREEK E	113.23	124.55	4.28
3489	ATUSIS CREEK SL	113.23	124.55	4.28
1275	BADGER EAST	113.23	124.55	4.28
1649	BADGER NORTH	113.23	124.55	4.28
1782	BAILEY'S BOTTOM	218.81	240.69	8.27
2744	BALLATER #2	286.09	314.70	10.81
1100	BANTRY	113.23	124.55	4.28
1296	BANTRY N.E.	113.23	124.55	4.28
1181	BANTRY N.W.	113.23	124.55	4.28
1122	BANTRY NORTH	113.23	124.55	4.28
1398	BAPTISTE	286.09	314.70	10.81
1339	BAPTISTE SOUTH	286.09	314.70	10.81
1497	BARICH	286.09	314.70	10.81
1329	BASHAW	220.35	242.39	8.33
1393	BASHAW B	220.20	242.22	8.32
1330	BASSANO SOUTH	113.23	124.55	4.28
1794	BASSANO SOUTH 2	113.23	124.55	4.28
2761	BASSET LAKE	286.09	314.70	10.81
2085	BASSET LAKE S.	286.09	314.70	10.81
2066	BASSET LAKE W.	286.09	314.70	10.81
1197	BAXTER LAKE	286.09	314.70	10.81
1334	BAXTER LAKE B	286.09	314.70	10.81
1382	BAXTER LAKE NW	286.09	314.70	10.81
1231	BAXTER LAKE S.	286.09	314.70	10.81
1198	BAXTER LAKE W.	286.09	314.70	10.81
2143	BAY TREE	286.09	314.70	10.81
2222	BEAR CANYON W.	259.38	285.32	9.80
2132	BEAR RIVER	286.09	314.70	10.81
1089	BELLIS	198.87	218.76	7.51
1675	BELLIS SOUTH	196.57	216.23	7.43
2043	BELLOY	267.37	294.11	10.10
2105	BELLOY WEST	229.32	252.25	8.66
1720	BELTZ LAKE	156.14	171.75	5.90
1264	BENALTO WEST	145.44	159.98	5.50

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2177	BENBOW SOUTH	195.92	215.51	7.40
1261	BENTLEY	128.05	140.86	4.84
1274	BENTON WEST	117.60	129.36	4.44
1604	BERRY CREEK S.	131.67	144.84	4.97
1136	BERRY CRK EAST	113.23	124.55	4.28
1085	BERRY-CAROLSIDE	113.23	124.55	4.28
1157	BIG BEND	286.09	314.70	10.81
1225	BIG BEND EAST	286.09	314.70	10.81
2175	BIG PRAIRIE	286.09	314.70	10.81
1835	BIGKNIFE CREEK	134.68	148.15	5.09
2176	BIGORAY RIVER	166.45	183.10	6.29
1002	BINDLOSS N. #1	113.23	124.55	4.28
1001	BINDLOSS SOUTH	113.23	124.55	4.28
1474	BINDLOSS WEST	176.60	194.26	6.67
2150	BINGLEY	113.23	124.55	4.28
2256	BISON LAKE	286.09	314.70	10.81
3446	BITTERN LAKE SL	286.09	314.70	10.81
1616	BLOOD IND CK E.	113.23	124.55	4.28
1505	BLOOD INDIAN CK	113.23	124.55	4.28
1779	BLOOR LAKE	214.05	235.46	8.09
1511	BLUE JAY	286.09	314.70	10.81
2704	BLUE RAPIDS	118.33	130.16	4.47
3471	BLUE RIDGE E SL	213.24	234.56	8.06
2119	BLUEBERRY HILL	286.09	314.70	10.81
1242	BODO WEST	190.22	209.24	7.19
1590	BOHN LAKE	286.09	314.70	10.81
5012	BOIVIN CREEK	286.09	314.70	10.81
1227	BOLLOQUE	286.09	314.70	10.81
1778	BOLLOQUE #2	286.09	314.70	10.81
1290	BOLLOQUE SOUTH	286.09	314.70	10.81
1401	BONAR WEST	113.23	124.55	4.28
1796	BONNIE GLEN	185.37	203.91	7.00
1660	BONNYVILLE	286.09	314.70	10.81
2709	BOOTIS HILL	286.09	314.70	10.81
2117	BOTHA	286.09	314.70	10.81
2182	BOTHA EAST	286.09	314.70	10.81

2217	BOTHA WEST	286.09	314.70	10.81
2220	BOULDER CREEK	286.09	314.70	10.81
3001	BOUNDARY LAKE S	258.22	284.04	9.76
3002	BOUNDARY LK BDR	261.45	287.60	9.88
1318	BOWELL SOUTH	127.67	140.44	4.82
1849	BOWELL SOUTH #2	127.67	140.44	4.82
1216	BOWMANTON	131.11	144.22	4.95
1842	BOWMANTON EAST	131.28	144.41	4.96
1204	BOWMANTON SOUTH	113.23	124.55	4.28
1237	BOWMANTON WEST	208.26	229.09	7.87
2138	BOYER EAST	286.09	314.70	10.81
1703	BOYLE WEST	220.35	242.39	8.33
1096	BRAZEAU SOUTH	135.00	148.50	5.10
1947	BRAZEAU/EAST SUMMARY	140.11	154.12	5.29
1619	BRIGGS	120.57	132.63	4.56
2721	BROWNVALE NORTH	215.20	236.72	8.13
2364	BROWNVALE SALES	256.40	282.04	9.69
1168	BRUCE	139.87	153.86	5.28
1409	BULLPOUND	125.82	138.40	4.75
1350	BULLPOUND SOUTH	206.84	227.52	7.81
1555	BULLSHEAD	170.24	187.26	6.43
2118	BURNT RIVER	227.03	249.73	8.58
2032	BURNT TIMBER	113.23	124.55	4.28
2181	BUTTE	113.23	124.55	4.28
1561	BYEMOOR	160.50	176.55	6.06
1725	CADOGAN	286.09	314.70	10.81
2221	CADOTTE RIVER	286.09	314.70	10.81
2738	CALAIS	204.38	224.82	7.72
2752	CALAIS NORTH	214.20	235.62	8.09
1373	CALLING LAKE	286.09	314.70	10.81
1522	CALLING LAKE E.	286.09	314.70	10.81
1443	CALLING LAKE W.	223.41	245.75	8.44
1676	CALLING LK N.	251.83	277.01	9.51
1387	CALLING LK S.	259.78	285.76	9.82
2743	CALLUM CREEK	113.23	124.55	4.28
1651	CAMROSE CREEK	286.09	314.70	10.81

1805	CANOE LAKE	286.09	314.70	10.81
3866	CARBON INTERCONNECTION	113.23	124.55	4.28
1622	CARBON WEST	113.23	124.55	4.28
1692	CARIBOU LAKE	286.09	314.70	10.81
2113	CAROLINE NORTH	113.23	124.55	4.28
3893	CARROT CREEK INTERCONNECTION	135.73	149.30	5.13
1840	CARSELAND RECEIPT	113.23	124.55	4.28
2018	CARSON CREEK	222.58	244.84	8.41
2188	CARSON CREEK E.	263.80	290.18	9.97
3330	CARSTAIRS INTERCONNECTION	113.23	124.55	4.28
1491	CASLAN	286.09	314.70	10.81
1492	CASLAN EAST	286.09	314.70	10.81
1315	CASSILS	116.43	128.07	4.40
1397	CASTOR	173.38	190.72	6.55
2727	CATTAIL LAKE	192.79	212.07	7.28
1737	CAVALIER	138.16	151.98	5.22
1228	CAVENDISH SOUTH	113.23	124.55	4.28
1025	CESSFORD EAST	113.23	124.55	4.28
1152	CESSFORD N.E.	113.23	124.55	4.28
1145	CESSFORD NORTH	113.23	124.55	4.28
1312	CESSFORD SOUTH	113.23	124.55	4.28
1086	CESSFORD W GAGE	113.23	124.55	4.28
1004	CESSFORD WARDLO	113.23	124.55	4.28
1012	CESSFORD WEST	113.23	124.55	4.28
1060	CESSFORD-BUR #2	113.23	124.55	4.28
1027	CESSFORD-BURF W	117.14	128.85	4.43
3907	CHANCELLOR INTERCONNECTION	113.23	124.55	4.28
1196	CHAUVIN	286.09	314.70	10.81
1666	CHEECHAM	286.09	314.70	10.81
1708	CHELSEA CREEK	286.09	314.70	10.81
1680	CHERRY GROVE E.	286.09	314.70	10.81
2705	CHESTER CREEK	286.09	314.70	10.81
2286	CHICKADEE CK W.	286.09	314.70	10.81
1034	CHIGWELL	212.67	233.94	8.04
1040	CHIGWELL EAST	202.59	222.85	7.65
2108	CHINCHAGA	272.06	299.27	10.28

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2266	CHINCHAGA WEST	286.09	314.70	10.81
1221	CHINOOK-CEREAL	148.99	163.89	5.63
5409	CHIP LAKE	135.85	149.44	5.13
3885	CHIP LAKE JCT	135.73	149.30	5.13
1609	CHISHOLM MILL W	286.09	314.70	10.81
1434	CHISHOLM MILLS	286.09	314.70	10.81
1322	CHOICE	286.09	314.70	10.81
1323	CHOICE B	286.09	314.70	10.81
1712	CHRISTINA LAKE	286.09	314.70	10.81
1679	CHUMP LAKE	286.09	314.70	10.81
1535	CLANDONALD	286.09	314.70	10.81
2070	CLARK LAKE	174.41	191.85	6.59
2063	CLEAR HILLS	264.32	290.75	9.99
2250	CLEAR HILLS N.	228.53	251.38	8.63
3008	CLEARDALE	286.09	314.70	10.81
1454	CLYDE	286.09	314.70	10.81
1803	CLYDE NORTH	286.09	314.70	10.81
3883	COALDALE JCT	113.23	124.55	4.28
5402	COALDALE S. B	122.03	134.23	4.61
3884	COALDALE S. JCT	113.23	124.55	4.28
1612	COATES LAKE	239.46	263.41	9.05
2735	CODESA	275.16	302.68	10.40
2152	CODNER	140.30	154.33	5.30
1417	COLD LAKE BDR	286.09	314.70	10.81
2003	COLEMAN	113.23	124.55	4.28
3052	COLEMAN SALES	113.23	124.55	4.28
1624	CONKLIN	286.09	314.70	10.81
1634	CONKLIN WEST	286.09	314.70	10.81
3904	CONKLIN WEST INTERCHANGE INTERCONNECTION	286.09	314.70	10.81
1713	CONN LAKE	286.09	314.70	10.81
1635	CONTRACOSTA E.	229.69	252.66	8.68
1614	CONTRACOSTA LK	173.76	191.14	6.57
2736	COPTON CREEK	249.49	274.44	9.43
1763	CORNER LAKE #2	286.09	314.70	10.81
1697	CORRIGALL LAKE	286.09	314.70	10.81
1667	COTTONWOOD CRK	286.09	314.70	10.81

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1028	COUNTESS	113.23	124.55	4.28
1015	COUNTESS MAKEPE	113.23	124.55	4.28
2296	COUNTESS S. #2	113.23	124.55	4.28
1287	COUNTESS WEST	160.85	176.94	6.08
1963	COUSINS B&C SALES	139.45	153.40	5.27
1433	COUSINS WEST	139.85	153.84	5.28
1112	CRAIGEND EAST	272.19	299.41	10.28
1320	CRAIGEND NORTH	286.09	314.70	10.81
1148	CRAIGEND SOUTH	286.09	314.70	10.81
1541	CRAIGMYLE	257.32	283.05	9.72
1583	CRAIGMYLE EAST	286.09	314.70	10.81
1686	CRAMMOND	113.23	124.55	4.28
2749	CRANBERRY LK #2	286.09	314.70	10.81
3105	CRANBERRY LK SL	286.09	314.70	10.81
1701	CROOKED LK S.	184.10	202.51	6.96
2724	CROOKED LK W.	170.67	187.74	6.45
2008	CROSSFIELD	113.23	124.55	4.28
3897	CROSSFIELD EAST #2 INTERCONNECTION	113.23	124.55	4.28
2017	CROSSFIELD WEST	113.23	124.55	4.28
1773	CROW LAKE SOUTH	286.09	314.70	10.81
2731	CROWELL	286.09	314.70	10.81
2718	CULP #2	286.09	314.70	10.81
1807	CULP NORTH	286.09	314.70	10.81
1489	CUTBANK RIVER	250.57	275.63	9.47
2209	CYNTHIA #2	123.53	135.88	4.67
1738	DANCING LAKE	286.09	314.70	10.81
1279	DAPP EAST	286.09	314.70	10.81
2289	DARLING CREEK	286.09	314.70	10.81
1529	DAYSLAND	146.40	161.04	5.53
2233	DEBOLT	267.23	293.95	10.10
1760	DECRENE EAST	286.09	314.70	10.81
1646	DECRENE NORTH	286.09	314.70	10.81
3888	DEEP VALLEY CREEK EAST INTERCONNECTION	232.86	256.15	8.80
2244	DEEP VLLY CRK S	166.48	183.13	6.29
1539	DELIA	208.11	228.92	7.86
1476	DEMMITT	266.43	293.07	10.07

3861	DEMMITT #2 INTERCONNECTION	266.42	293.06	10.07
1734	DEVENISH SOUTH	286.09	314.70	10.81
1733	DEVENISH WEST	286.09	314.70	10.81
1793	DIAMOND CITY	151.60	166.76	5.73
1185	DISMAL CREEK	148.03	162.83	5.59
2210	DIXONVILLE N #2	226.42	249.06	8.55
2110	DIXONVILLE N.	286.09	314.70	10.81
2197	DOE CREEK	286.09	314.70	10.81
2712	DOE CREEK S.	286.09	314.70	10.81
1147	DONALDA	250.62	275.68	9.47
1520	DONATVILLE	264.58	291.04	10.00
2139	DONNELLY	286.09	314.70	10.81
2297	DORIS CREEK S.	286.09	314.70	10.81
1236	DOROTHY	178.12	195.93	6.73
1818	DOWLING	113.23	124.55	4.28
2719	DREAU	282.77	311.05	10.68
1689	DROPOFF CREEK	286.09	314.70	10.81
5022	DUNKIRK RIVER	286.09	314.70	10.81
1220	DUNMORE	152.00	167.20	5.74
2044	DUNVEGAN	234.23	257.65	8.85
2716	DUNVEGAN W. #2	285.74	314.31	10.80
2084	DUNVEGAN WEST	285.74	314.31	10.80
3062	E. CALGARY B SL	113.23	124.55	4.28
2081	EAGLE HILL	143.39	157.73	5.42
2097	EAGLESHAM	202.14	222.35	7.64
2007	EAST CALGARY	113.23	124.55	4.28
1568	EDBERG	244.83	269.31	9.25
1265	EDGERTON	286.09	314.70	10.81
1266	EDGERTON WEST	286.09	314.70	10.81
1064	EDSON	145.25	159.78	5.49
1213	EDWAND	220.25	242.28	8.32
1467	EDWAND SOUTH	217.49	239.24	8.22
A44A	EKWAN	286.09	314.70	10.81
1715	ELINOR LAKE	286.09	314.70	10.81
1742	ELINOR LAKE E.	286.09	314.70	10.81
1558	ELK RIVER SOUTH	136.02	149.62	5.14

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1615	ELMWORTH HIGH	203.16	223.48	7.68
1958	EMPRESS BORDER	113.23	124.55	4.28
1024	ENCHANT	120.48	132.53	4.55
1507	ENDIANG	113.23	124.55	4.28
1074	EQUITY	129.03	141.93	4.88
1359	EQUITY B	144.55	159.01	5.46
1586	EQUITY EAST	147.39	162.13	5.57
1232	ERSKINE NORTH	195.74	215.31	7.40
1746	ESTRIDGE LAKE	286.09	314.70	10.81
2049	ETA LAKE	141.17	155.29	5.33
1547	ETZIKOM A	275.47	303.02	10.41
1548	ETZIKOM B	275.45	303.00	10.41
1557	ETZIKOM D	275.73	303.30	10.42
1677	FAIRYDELL CREEK	286.09	314.70	10.81
3112	FALHER SALES	286.09	314.70	10.81
2729	FARIA	286.09	314.70	10.81
1375	FAWCETT RIVER	286.09	314.70	10.81
1389	FAWCETT RIVER E	286.09	314.70	10.81
1753	FAWCETT RVR N.	286.09	314.70	10.81
1659	FERINTOSH WEST	286.09	314.70	10.81
2016	FERRIER	141.25	155.38	5.34
1101	FERRIER NORTH	135.08	148.59	5.10
2115	FERRIER SOUTH A	141.32	155.45	5.34
1111	FERRIER SOUTH B	146.62	161.28	5.54
1942	FIGURE LAKE SUMMARY	255.04	280.54	9.64
1300	FITZALLAN SOUTH	215.90	237.49	8.16
1095	FLAT LAKE	286.09	314.70	10.81
1302	FLAT LAKE NORTH	286.09	314.70	10.81
1394	FLATBUSH	286.09	314.70	10.81
1632	FOISY	237.78	261.56	8.98
2251	FONTAS RIVER	286.09	314.70	10.81
3304	FORESTBURG SLS	123.25	135.58	4.66
1376	FORSHEE	120.17	132.19	4.54
1602	FORT KENT	286.09	314.70	10.81
2199	FOULWATER CREEK	286.09	314.70	10.81
2103	FOURTH CREEK	286.09	314.70	10.81

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2178	FOURTH CREEK S.	286.09	314.70	10.81
2198	FOURTH CREEK W.	286.09	314.70	10.81
2268	FRAKES FLATS	209.09	230.00	7.90
2078	GARRINGTON	113.23	124.55	4.28
2079	GARRINGTON EAST	136.60	150.26	5.16
1623	GATINE	113.23	124.55	4.28
1435	GEM SOUTH	113.23	124.55	4.28
1490	GEM WEST	113.23	124.55	4.28
1073	GHOSTPINE	113.23	124.55	4.28
1617	GHOSTPINE 'B'	113.23	124.55	4.28
1037	GILBY #2	131.87	145.06	4.98
1084	GILBY SOUTH PAC	131.86	145.05	4.98
2037	GILBY WEST	142.64	156.90	5.39
2722	GILMORE LAKE	222.91	245.20	8.42
3894	GILT EDGE WEST INTERCONNECTION	286.09	314.70	10.81
1480	GLEICHEN	195.45	215.00	7.38
1456	GLENDON	286.09	314.70	10.81
2290	GODS LAKE	286.09	314.70	10.81
2031	GOLD CREEK	185.71	204.28	7.02
1452	GOODFARE	244.96	269.46	9.26
1504	GOODRIDGE	286.09	314.70	10.81
1783	GOODRIDGE NORTH	286.09	314.70	10.81
1798	GOOSEQUILL	239.01	262.91	9.03
3886	GORDONDALE BORDER	250.43	275.47	9.46
1560	GOUGH LAKE	116.63	128.29	4.41
1448	GRACE CREEK	144.22	158.64	5.45
1482	GRAHAM	286.09	314.70	10.81
1352	GRAINGER	113.23	124.55	4.28
2129	GRANADA	166.55	183.21	6.29
3424	GRANDE CENTRE S	286.09	314.70	10.81
5005	GRANOR	286.09	314.70	10.81
1093	GREENCOURT	230.88	253.97	8.72
1267	GREGORY	113.23	124.55	4.28
1365	GREGORY N.E.	113.23	124.55	4.28
1259	GREGORY WEST	113.23	124.55	4.28
5025	GREW LAKE	286.09	314.70	10.81

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5028	GREW LK EAST	286.09	314.70	10.81
1647	GRIST LAKE	286.09	314.70	10.81
1538	HACKETT	276.20	303.82	10.44
1722	HACKETT WEST	286.09	314.70	10.81
1576	HADDOCK	172.18	189.40	6.51
1589	HADDOCK NORTH	177.15	194.87	6.69
1636	HADDOCK SOUTH	202.68	222.95	7.66
2086	HAIG RIVER	286.09	314.70	10.81
2064	HAIG RIVER EAST	286.09	314.70	10.81
2127	HAIG RIVER N.	286.09	314.70	10.81
1230	HAIRY HILL	209.67	230.64	7.92
1391	HALKIRK	145.75	160.33	5.51
1834	HALKIRK NORTH#2	113.81	125.19	4.30
3915	HAMILTON LAKE SUMMARY	255.30	280.83	9.65
1291	HAMLIN	286.09	314.70	10.81
1182	HANNA	113.23	124.55	4.28
1444	HARDISTY	258.75	284.63	9.78
1166	HARMATTAN-ELKTN	113.23	124.55	4.28
2145	HARO RIVER N.	286.09	314.70	10.81
1850	HARTELL SOUTH	113.23	124.55	4.28
1709	HASTINGS COULEE	181.43	199.57	6.85
1418	HATTIE LAKE N.	286.09	314.70	10.81
2126	HAY RIVER	286.09	314.70	10.81
2278	HAY RIVER SOUTH	286.09	314.70	10.81
1603	HAYS	213.08	234.39	8.05
2140	HEART RIVER	286.09	314.70	10.81
1439	HEISLER	125.38	137.92	4.74
1523	HELINA	286.09	314.70	10.81
2174	HENDERSON CK SE	281.78	309.96	10.65
2164	HENDERSON CREEK	276.69	304.36	10.45
1673	HERMIT LAKE	242.89	267.18	9.18
3611	HERMIT LAKE SLS	243.00	267.30	9.18
2059	HINES CREEK	286.09	314.70	10.81
2219	HINES CREEK W.	286.09	314.70	10.81
1161	HOLDEN	198.19	218.01	7.49
1528	HOOLE	286.09	314.70	10.81

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1411	HORBURG	119.65	131.62	4.52
2047	HOTCHKISS	286.09	314.70	10.81
2065	HOTCHKISS EAST	286.09	314.70	10.81
2094	HOTCHKISS NE B	286.09	314.70	10.81
2095	HOTCHKISS NE C	286.09	314.70	10.81
2054	HOTCHKISS NORTH	286.09	314.70	10.81
5007	HOUSE RIVER	286.09	314.70	10.81
2169	HOWARD CREEK E.	286.09	314.70	10.81
1207	HUDSON	179.65	197.62	6.79
1413	HUDSON WEST	150.10	165.11	5.67
2277	HUNT CREEK	286.09	314.70	10.81
2751	HUNT CREEK #2	286.09	314.70	10.81
1436	HUSSAR NORTH	113.23	124.55	4.28
1016	HUSSAR-CHANCELL	113.23	124.55	4.28
1142	HUXLEY	133.98	147.38	5.06
1591	HUXLEY EAST	258.63	284.49	9.77
1241	HYLO	286.09	314.70	10.81
1357	HYLO SOUTH	286.09	314.70	10.81
1479	HYTHE	254.70	280.17	9.62
1277	IDDESLEIGH S.	113.23	124.55	4.28
1678	INDIAN LAKE	164.82	181.30	6.23
1717	INDIAN LAKE #2	164.18	180.60	6.20
3857	INLAND INTERCONNECTION	173.47	190.82	6.55
1685	IPIATIK LAKE	286.09	314.70	10.81
1441	IRISH	286.09	314.70	10.81
1593	IRON SPRINGS	113.23	124.55	4.28
1569	IROQUOIS CREEK	199.93	219.92	7.55
1201	IRVINE	172.87	190.16	6.53
1407	ISLAND LAKE	247.52	272.27	9.35
1700	ISLAND LAKE #2	247.46	272.21	9.35
1694	JACKFISH CREEK	286.09	314.70	10.81
2723	JACKPOT CREEK	286.09	314.70	10.81
2146	JACKSON CREEK	113.23	124.55	4.28
3860	JANUARY CREEK INTERCONNECTION	154.00	169.40	5.82
1163	JARROW	286.09	314.70	10.81
1159	JARROW SOUTH	269.55	296.51	10.18

1281	JARROW WEST	286.09	314.70	10.81
1799	JARVIE NORTH	286.09	314.70	10.81
1143	JENNER EAST	113.23	124.55	4.28
1099	JENNER WEST	113.23	124.55	4.28
1385	JENNER WEST B	113.23	124.55	4.28
1167	JOFFRE	191.68	210.85	7.24
3864	JOFFRE #2 AND #3 SALES INTERCONNECTION	132.07	145.28	4.99
2267	JONES LAKE	228.25	251.08	8.62
2279	JONES LAKE #2	228.46	251.31	8.63
2272	JONES LAKE EAST	246.98	271.68	9.33
2241	JONES LAKE N.	264.04	290.44	9.98
2087	JOSEPHINE	284.72	313.19	10.76
2083	JOSEPHINE EAST	286.09	314.70	10.81
2022	JUDY CREEK	284.63	313.09	10.75
2036	JUMPING POUND W	113.23	124.55	4.28
1811	KAKWA	227.79	250.57	8.61
1462	KARR	181.94	200.13	6.87
2013	KAYBOB	197.67	217.44	7.47
2027	KAYBOB 11-36	195.52	215.07	7.39
2020	KAYBOB SOUTH	183.78	202.16	6.94
2035	KAYBOB SOUTH #3	158.79	174.67	6.00
2053	KEG RIVER	286.09	314.70	10.81
2068	KEG RIVER EAST	286.09	314.70	10.81
2216	KEG RIVER NORTH	286.09	314.70	10.81
1517	KEHIWIN	286.09	314.70	10.81
1224	KEHO LAKE	113.23	124.55	4.28
1775	KEHO LAKE NORTH	124.72	137.19	4.71
2748	KEMP RIVER	286.09	314.70	10.81
1483	KENT	286.09	314.70	10.81
2739	KEPPLER CREEK	286.09	314.70	10.81
1845	KERSEY	113.23	124.55	4.28
1627	KETTLE RIVER	286.09	314.70	10.81
2288	KIDNEY LAKE	286.09	314.70	10.81
1608	KIKINO	263.67	290.04	9.96
1772	KIKINO NORTH	234.08	257.49	8.84
1162	KILLAM	286.09	314.70	10.81

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1298	KILLAM NORTH	286.09	314.70	10.81
1682	KINOSIS	286.09	314.70	10.81
1446	KIRBY	286.09	314.70	10.81
1449	KIRBY NORTH	286.09	314.70	10.81
1727	KIRBY NORTH #2	286.09	314.70	10.81
2134	KSITUAN RIVER	273.51	300.86	10.33
2759	KSITUAN RIVER EAST #2	286.09	314.70	10.81
1721	LAC LA BICHE	286.09	314.70	10.81
1718	LACOREY	286.09	314.70	10.81
2287	LAFOND CREEK	286.09	314.70	10.81
1210	LAKE NEWELL E.	152.65	167.92	5.77
1562	LAKEVIEW LAKE	116.93	128.62	4.42
1828	LAKEVIEW LAKE #2	113.23	124.55	4.28
2737	LALBY CREEK	286.09	314.70	10.81
1767	LAMERTON	286.09	314.70	10.81
1206	LANFINE	121.63	133.79	4.60
1564	LARKSPUR	286.09	314.70	10.81
2223	LAST LAKE	236.55	260.21	8.94
2151	LASTHILL CREEK	113.23	124.55	4.28
2259	LATHROP CREEK	268.45	295.30	10.14
1132	LAVOY	208.64	229.50	7.88
1324	LAWRENCE LAKE	286.09	314.70	10.81
1695	LAWRENCE LAKE N	286.09	314.70	10.81
2040	LEAFLAND	187.82	206.60	7.10
1833	LEE LAKE	200.26	220.29	7.57
2179	LEEDALE	113.23	124.55	4.28
3605	LEMING LAKE SLS	286.09	314.70	10.81
2249	LENNARD CREEK	286.09	314.70	10.81
1272	LEO	113.23	124.55	4.28
5003	LIEGE	286.09	314.70	10.81
5083	LIEGE NORTH	286.09	314.70	10.81
1536	LINARIA	286.09	314.70	10.81
1494	LITTLE SUNDANCE	147.16	161.88	5.56
2111	LOBSTICK	134.68	148.15	5.09
1465	LONE BUTTE	192.00	211.20	7.25
1069	LONE PINE CREEK	113.23	124.55	4.28

1139	LONE PINE SOUTH	113.23	124.55	4.28
1768	LONESOME LAKE	114.38	125.82	4.32
1630	LONG LAKE WEST	286.09	314.70	10.81
1366	LOUISIANA LAKE	144.87	159.36	5.47
1496	LOUSANA	239.09	263.00	9.03
2128	LOVET CREEK	286.09	314.70	10.81
1386	LUCKY LAKE	286.09	314.70	10.81
3058	LUNDBRECK-COWLE	113.23	124.55	4.28
5021	MACKAY RIVER	286.09	314.70	10.81
2702	MAHASKA	214.18	235.60	8.09
2700	MAHASKA WEST	178.83	196.71	6.76
1229	MAJESTIC	132.10	145.31	4.99
1419	MAKEPEACE NORTH	113.23	124.55	4.28
1719	MANATOKEN LAKE	286.09	314.70	10.81
2720	MANIR	265.95	292.55	10.05
1273	MAPLE GLEN	113.23	124.55	4.28
1572	MARLBORO	200.36	220.40	7.57
1663	MARLBORO EAST	200.55	220.61	7.58
2713	MARLOW CREEK	286.09	314.70	10.81
2750	MARSH HEAD CK WEST	161.41	177.55	6.10
2762	MARSH HEAD CREEK WEST #2	161.38	177.52	6.10
2228	MARSH HEAD CRK	180.48	198.53	6.82
1091	MARTEN HILLS	286.09	314.70	10.81
1672	MARTEN HILLS N.	286.09	314.70	10.81
1097	MARTEN HILLS S.	286.09	314.70	10.81
1769	MASTIN LAKE	281.02	309.12	10.62
1270	MATZHIWIN EAST	135.57	149.13	5.12
1284	MATZHIWIN N.E.	113.23	124.55	4.28
1379	MATZHIWIN SOUTH	113.23	124.55	4.28
1288	MATZHIWIN W. B	113.23	124.55	4.28
1150	MATZHIWIN WEST	113.23	124.55	4.28
1514	MAUGHAN	286.09	314.70	10.81
1633	MAY HILL	286.09	314.70	10.81
2706	MCLEAN CREEK	286.09	314.70	10.81
2144	MCLENNAN	286.09	314.70	10.81
2710	MCMILLAN LAKE	286.09	314.70	10.81

6404	MCNEILL BORDER	113.23	124.55	4.28
1704	MEADOW CREEK	286.09	314.70	10.81
1707	MEADOW CREEK E.	286.09	314.70	10.81
1705	MEADOW CRK WEST	286.09	314.70	10.81
1338	MEANOOK	286.09	314.70	10.81
1017	MED HAT N. #1	113.23	124.55	4.28
1184	MED HAT N. ARCO	113.23	124.55	4.28
1325	MED HAT N. F	113.23	124.55	4.28
1205	MED HAT N.W.	113.23	124.55	4.28
1018	MED HAT S. #1	113.23	124.55	4.28
1043	MED HAT S. #2	113.23	124.55	4.28
1128	MED HAT S. #4	113.23	124.55	4.28
1172	MED HAT WEST	113.23	124.55	4.28
1186	MEDICINE HAT E.	113.23	124.55	4.28
1214	MEDICINE RVR A	264.43	290.87	9.99
1645	METISKOW NORTH	210.66	231.73	7.96
1362	MEYER	286.09	314.70	10.81
1508	MICHICHI	187.68	206.45	7.09
1146	MIKWAN	175.76	193.34	6.64
1427	MIKWAN EAST	276.24	303.86	10.44
1144	MIKWAN NORTH	135.75	149.33	5.13
2237	MILLERS LAKE	155.93	171.52	5.89
1524	MILLS	286.09	314.70	10.81
1578	MILO	113.23	124.55	4.28
1396	MINBURN	286.09	314.70	10.81
2149	MINNEHIK-BK L B	132.34	145.57	5.00
2010	MINNEHIK-BK LK	131.63	144.79	4.97
1693	MINNOW LAKE	198.72	218.59	7.51
1658	MIQUELON LAKE	286.09	314.70	10.81
2273	MIRAGE	273.65	301.02	10.34
1500	MIRROR	204.26	224.69	7.72
1090	MITSUE	286.09	314.70	10.81
3889	MITSUE INTERCONNECTION	286.09	314.70	10.81
1457	MITSUE SOUTH	286.09	314.70	10.81
3863	MONARCH INTERCONNECTION	113.23	124.55	4.28
1605	MONITOR CREEK	134.74	148.21	5.09

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1771	MONITOR CREEK W	204.44	224.88	7.72
1222	MONITOR SOUTH	141.14	155.25	5.33
1292	MONS LAKE	286.09	314.70	10.81
1355	MONS LAKE EAST	286.09	314.70	10.81
1823	MOOSE PORTAGE	227.77	250.55	8.61
1484	MOOSELAKE RIVER	286.09	314.70	10.81
1460	MORECAMBE	286.09	314.70	10.81
1458	MORRIN	187.02	205.72	7.07
1781	MOSS LAKE	286.09	314.70	10.81
1802	MOSS LAKE NORTH	250.97	276.07	9.48
1641	MOUNT VALLEY	248.14	272.95	9.38
2732	MOUNTAIN LAKE	245.88	270.47	9.29
1774	MUNSON	252.01	277.21	9.52
1551	MURRAY LAKE	213.70	235.07	8.07
1843	MURRAY LAKE NORTH	207.87	228.66	7.85
2236	MUSKEG CREEK	286.09	314.70	10.81
1785	MUSKWA RIVER	286.09	314.70	10.81
2711	MUSREAU LAKE	265.63	292.19	10.04
1730	MYRNAM	286.09	314.70	10.81
2745	NARRAWAY RIVER	273.33	300.66	10.33
3009	NEPTUNE	258.34	284.17	9.76
1276	NESTOW	267.54	294.29	10.11
1316	NETOOK	286.09	314.70	10.81
1020	NEVIS NORTH	157.83	173.61	5.96
1019	NEVIS SOUTH	152.55	167.81	5.76
1502	NEWBROOK	286.09	314.70	10.81
1140	NEWELL NORTH	113.23	124.55	4.28
1747	NIGHTINGALE	113.23	124.55	4.28
2242	NIOBE CREEK	248.13	272.94	9.37
1194	NIPISI	286.09	314.70	10.81
1776	NISBET LAKE	286.09	314.70	10.81
2071	NITON	148.99	163.89	5.63
2172	NITON NORTH	162.38	178.62	6.14
3368	NOEL LAKE SALES	231.91	255.10	8.76
2714	NOEL LAKE SOUTH	221.30	243.43	8.36
2192	NOTIKEWIN RIVER	286.09	314.70	10.81

2218	NOTIKEWIN RVR N	278.34	306.17	10.52
1824	OBED CREEK	183.25	201.58	6.92
1829	OBED NORTH	150.79	165.87	5.70
1053	OLDS	122.48	134.73	4.63
1545	OPAL	286.09	314.70	10.81
1814	ORLOFF LAKE	286.09	314.70	10.81
2726	ORTON M/S	113.23	124.55	4.28
1716	OSBORNE LAKE	286.09	314.70	10.81
1812	OSLAND LAKE	276.87	304.56	10.46
1587	OVERLEA	286.09	314.70	10.81
1817	OWL LAKE	278.73	306.60	10.53
2728	OWL LAKE SOUTH	273.74	301.11	10.34
2742	OWL LAKE STH #2	273.48	300.83	10.33
2746	OWL LAKE STH #3	273.48	300.83	10.33
1495	OWLSEYE	286.09	314.70	10.81
1007	OYEN	127.95	140.75	4.83
1058	OYEN NORTH	113.23	124.55	4.28
2098	PADDLE PRAIR S.	286.09	314.70	10.81
2093	PADDLE PRAIRIE	286.09	314.70	10.81
1307	PADDLE RIVER	244.84	269.32	9.25
1852	PAKAN LAKE	236.45	260.10	8.93
1728	PARADISE VALLEY	286.09	314.70	10.81
1665	PARSONS LAKE	286.09	314.70	10.81
2089	PASS CREEK	173.35	190.69	6.55
2168	PASS CREEK WEST	166.85	183.54	6.30
2260	PASTECHO RIVER	286.09	314.70	10.81
1278	PATRICIA	113.23	124.55	4.28
1289	PATRICIA WEST	113.23	124.55	4.28
3804	PEMBINA INTERCONNECTION	116.46	128.11	4.40
2185	PEMBINA WEST	128.74	141.61	4.86
1180	PENHOLD	113.23	124.55	4.28
3454	PENHOLD N SALES	113.23	124.55	4.28
1607	PENHOLD WEST	143.65	158.02	5.43
2280	PETE LAKE	279.76	307.74	10.57
2247	PETE LAKE SOUTH	225.76	248.34	8.53
1714	PICHE LAKE	286.09	314.70	10.81

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1610	PICTURE BUTTE	201.87	222.06	7.63
2046	PIONEER	139.04	152.94	5.25
2088	PIONEER EAST	180.03	198.03	6.80
1739	PIPER CREEK	140.58	154.64	5.31
1797	PITLO	286.09	314.70	10.81
1110	PLAIN LAKE	261.56	287.72	9.88
1710	PLEASANT WEST	286.09	314.70	10.81
2173	POISON CREEK	188.29	207.12	7.11
3879	PRIDDIS INTERCONNECTION	113.23	124.55	4.28
1246	PRINCESS EAST	113.23	124.55	4.28
1327	PRINCESS SOUTH	113.23	124.55	4.28
1183	PRINCESS WEST	113.23	124.55	4.28
1010	PRINCESS-DENHAR	113.23	124.55	4.28
1022	PRINCESS-IDDESL	113.23	124.55	4.28
2153	PROGRESS	235.93	259.52	8.91
2191	PROGRESS EAST	242.71	266.98	9.17
1304	PROSPERITY	264.77	291.25	10.00
1211	PROVOST MONITOR	254.42	279.86	9.61
1003	PROVOST NORTH	153.18	168.50	5.79
1013	PROVOST SOUTH	165.47	182.02	6.25
1045	PROVOST WEST	225.40	247.94	8.52
1038	PROVOST-KESSLER	245.25	269.78	9.27
1601	QUEENSTOWN	216.27	237.90	8.17
2026	QUIRK CREEK	113.23	124.55	4.28
1741	RABBIT LAKE	286.09	314.70	10.81
2201	RAINBOW LAKE S.	286.09	314.70	10.81
1106	RAINIER	113.23	124.55	4.28
1380	RAINIER S.W.	113.23	124.55	4.28
1378	RAINIER SOUTH	136.90	150.59	5.17
1282	RALSTON	113.23	124.55	4.28
1826	RALSTON SOUTH	113.23	124.55	4.28
2148	RAMBLING CREEK	286.09	314.70	10.81
2213	RAMBLING CRK E.	286.09	314.70	10.81
1164	RANFURLY	265.29	291.82	10.02
3911	RANFURLY INTERCONNECTION	265.33	291.86	10.02
1189	RANFURLY NORTH	189.28	208.21	7.15

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1165	RANFURLY WEST	226.48	249.13	8.56
2211	RASPBERRY LAKE	238.41	262.25	9.01
2104	RAT CREEK	121.42	133.56	4.59
2265	RAT CREEK SOUTH	134.57	148.03	5.08
2252	RAT CREEK WEST	144.06	158.47	5.44
2193	RAY LAKE SOUTH	286.09	314.70	10.81
2166	RAY LAKE WEST	286.09	314.70	10.81
1209	REDCLIFF	148.14	162.95	5.60
1219	REDCLIFF SOUTH	127.97	140.77	4.84
1838	REDCLIFF STH #2	127.97	140.77	4.84
1346	REDCLIFF WEST	146.29	160.92	5.53
3438	REDWATER 'B' SL	286.09	314.70	10.81
3406	REDWATER SALES	286.09	314.70	10.81
1057	RETLAW	113.23	124.55	4.28
1218	RETLAW SOUTH	121.19	133.31	4.58
1392	RIBSTONE	286.09	314.70	10.81
1374	RICH LAKE	286.09	314.70	10.81
1135	RICINUS	119.11	131.02	4.50
1372	RICINUS SOUTH	117.23	128.95	4.43
1437	RICINUS WEST	124.51	136.96	4.70
1949	RIMBEY/WESTEROSE SUMMARY	128.60	141.46	4.86
3405	RIM-WEST SALES	128.60	141.46	4.86
1510	RIVERCOURSE	286.09	314.70	10.81
1499	ROBB	163.64	180.00	6.18
1336	ROCHESTER	286.09	314.70	10.81
1400	ROCK ISLAND LK	286.09	314.70	10.81
1820	ROCK ISLAND S2	286.09	314.70	10.81
1134	ROCKYFORD	113.23	124.55	4.28
2715	ROD LAKE	286.09	314.70	10.81
1468	ROSALIND	156.43	172.07	5.91
1579	ROSE LYNNE	113.23	124.55	4.28
1466	ROSEMARY	113.23	124.55	4.28
1461	ROSEMARY NORTH	113.23	124.55	4.28
2099	ROSEVEAR SOUTH	156.34	171.97	5.91
2725	ROSSBEAR LAKE	286.09	314.70	10.81
1706	ROURKE CRK EAST	286.09	314.70	10.81

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1540	ROWLEY	182.75	201.03	6.90
1299	ROYAL PARK	179.99	197.99	6.80
1530	RUMSEY	183.34	201.67	6.93
1600	RUMSEY WEST	223.85	246.24	8.46
3912	RUNNING LAKE INTERCONNECTION	286.09	314.70	10.81
2261	RUSSELL CREEK	286.09	314.70	10.81
1311	SADDLE LAKE N.	249.33	274.26	9.42
1310	SADDLE LAKE W.	286.09	314.70	10.81
5004	SALESKI	286.09	314.70	10.81
2281	SAND CREEK	133.59	146.95	5.05
2758	SAWN LAKE	286.09	314.70	10.81
3481	SAWRIDGE SALES	286.09	314.70	10.81
1537	SCOTFIELD	207.02	227.72	7.82
1827	SEDALIA	113.23	124.55	4.28
1036	SEDALIA NORTH	210.88	231.97	7.97
1023	SEDALIA SOUTH	124.92	137.41	4.72
1114	SEDGEWICK	286.09	314.70	10.81
1395	SEDGEWICK EAST	286.09	314.70	10.81
1403	SEDGEWICK NORTH	280.09	308.10	10.58
1447	SEIU CREEK	113.23	124.55	4.28
1370	SEPTEMBER LK N.	286.09	314.70	10.81
1847	SERVICEBERRY CREEK	113.23	124.55	4.28
3862	SEVERN CREEK INTERCONNECTION	113.23	124.55	4.28
1846	SHARROW SOUTH#2	113.23	124.55	4.28
3439	SHEERNESS SALES	113.23	124.55	4.28
2276	SHEKILIE RVR N.	286.09	314.70	10.81
2170	SILVERWOOD	286.09	314.70	10.81
2239	SILVERWOOD N.	267.79	294.57	10.12
1806	SIMON LAKES	286.09	314.70	10.81
2028	SIMONETTE	232.84	256.12	8.80
2033	SIMONETTE NORTH	233.01	256.31	8.80
1354	SLAWA NORTH	286.09	314.70	10.81
2235	SLIMS LAKE	286.09	314.70	10.81
2137	SLOAT CREEK	286.09	314.70	10.81
1521	SMITH	286.09	314.70	10.81
1637	SMITH WEST	286.09	314.70	10.81

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2165	SNEDDON CREEK	286.09	314.70	10.81
2253	SNIPE LAKE	286.09	314.70	10.81
2264	SNOWFALL CREEK	286.09	314.70	10.81
1065	SOUTH ELKTON	219.04	240.94	8.28
1556	SOUTH SASK RVR	241.51	265.66	9.12
1580	SPEAR LAKE	286.09	314.70	10.81
1341	SPRUCEFIELD	286.09	314.70	10.81
1487	SPURFIELD	286.09	314.70	10.81
1581	SQUARE LAKE	286.09	314.70	10.81
1519	ST. BRIDES	286.09	314.70	10.81
1414	ST. LINA	286.09	314.70	10.81
1415	ST. LINA NORTH	286.09	314.70	10.81
1416	ST. LINA WEST	286.09	314.70	10.81
1534	STANDARD	113.23	124.55	4.28
1131	STANMORE	125.39	137.93	4.74
1156	STANMORE SOUTH	118.37	130.21	4.47
1371	STEELE LAKE	286.09	314.70	10.81
2284	STEEN RIVER	286.09	314.70	10.81
1308	STETTLER SOUTH	220.14	242.15	8.32
1388	STEVEVILLE	113.23	124.55	4.28
1565	STONEY CREEK	277.43	305.17	10.48
1566	STONEY CREEK W.	246.12	270.73	9.30
2740	STOWE CREEK	238.30	262.13	9.00
1115	STRACHAN	113.23	124.55	4.28
1179	STROME-HOLMBERG	171.14	188.25	6.47
2030	STURGEON LAKE S	251.96	277.16	9.52
1423	SUFFIELD WEST	120.56	132.62	4.56
1193	SULLIVAN LAKE	181.55	199.71	6.86
1516	SUNDANCE CREEK	208.78	229.66	7.89
1595	SUNDANCE CRK E.	148.21	163.03	5.60
1674	SUNDAY CREEK	286.09	314.70	10.81
1696	SUNDAY CREEK S.	286.09	314.70	10.81
1079	SUNNYNOOK	113.23	124.55	4.28
1054	SYLVAN LAKE	128.14	140.95	4.84
1187	SYLVAN LAKE E. #1	122.89	135.18	4.64
1191	SYLVAN LK SOUTH	141.17	155.29	5.33

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1055	SYLVAN LK WEST	138.86	152.75	5.25
2082	TANGENT	286.09	314.70	10.81
2121	TANGENT B	286.09	314.70	10.81
2208	TANGENT EAST	286.09	314.70	10.81
2157	TANGHE CREEK	278.59	306.45	10.53
2204	TANGHE CREEK #2	279.36	307.30	10.55
2747	TANGHE CREEK #3	278.75	306.63	10.53
1440	TAPLOW	113.23	124.55	4.28
1837	TAWADINA CREEK	113.23	124.55	4.28
2076	TEEPEE CREEK	286.09	314.70	10.81
5027	THICKWOOD HILLS	286.09	314.70	10.81
1377	THORHILD	286.09	314.70	10.81
1430	THORHILD WEST	248.77	273.65	9.40
1029	THREE HILLS CRK	136.64	150.30	5.16
1335	THREE HLS CRK W	113.23	124.55	4.28
1348	TIDE LAKE	113.23	124.55	4.28
1639	TIDE LAKE B	113.23	124.55	4.28
1331	TIDE LAKE EAST	113.23	124.55	4.28
1268	TIDE LAKE NORTH	113.23	124.55	4.28
1223	TIDE LAKE SOUTH	113.23	124.55	4.28
1412	TIELAND	286.09	314.70	10.81
1314	TILLEBROOK	113.23	124.55	4.28
1644	TILLEBROOK WEST	113.23	124.55	4.28
1169	TILLEY	113.23	124.55	4.28
1839	TILLEY SOUTH #2	215.96	237.56	8.16
2116	TONY CREEK N.	213.01	234.31	8.05
2754	TOPLAND	270.55	297.61	10.22
1841	TORLEA EAST	207.45	228.20	7.84
1621	TORRINGTON EAST	113.23	124.55	4.28
1442	TRAVERS	113.23	124.55	4.28
1574	TROCHU	163.65	180.02	6.18
1848	TUDOR	113.23	124.55	4.28
1343	TWEEDIE	286.09	314.70	10.81
1256	TWEEDIE SOUTH	286.09	314.70	10.81
1190	TWINING	113.23	124.55	4.28
1066	TWINING NORTH	118.81	130.69	4.49

3113	TWINLAKES CK SL	286.09	314.70	10.81
2224	TWO CREEKS	286.09	314.70	10.81
2229	TWO CREEKS EAST	286.09	314.70	10.81
1120	UKALTA	258.95	284.85	9.78
1317	UKALTA EAST	224.55	247.01	8.48
1250	UNITY BORDER	201.41	221.55	7.61
1154	VALE	113.23	124.55	4.28
1212	VALE EAST	146.15	160.77	5.52
2107	VALHALLA	238.83	262.71	9.02
2227	VALHALLA #2	238.79	262.67	9.02
2189	VALHALLA EAST	249.56	274.52	9.43
1801	VANDERSTEENE LK	286.09	314.70	10.81
1056	VERGER	113.23	124.55	4.28
1077	VERGER-HOMESTEA	113.23	124.55	4.28
1203	VERGER-MILLICEN	113.23	124.55	4.28
3916	VETERAN SUMMARY	255.30	280.83	9.65
1606	VICTOR	248.00	272.80	9.37
1347	VIKING EAST	171.98	189.18	6.50
3890	VIKING INTERCONNECTION	163.10	179.41	6.16
1257	VIKING NORTH	233.18	256.50	8.81
1464	VILNA	286.09	314.70	10.81
1527	VIMY	286.09	314.70	10.81
2034	VIRGINIA HILLS	286.09	314.70	10.81
1076	VULCAN	119.57	131.53	4.52
1724	WABASCA	286.09	314.70	10.81
1669	WADDELL CREEK	286.09	314.70	10.81
1736	WADDELL CREEK W	286.09	314.70	10.81
1383	WAINWRIGHT EAST	286.09	314.70	10.81
1199	WAINWRIGHT S.	275.91	303.50	10.42
1822	WANDERING RIVER	286.09	314.70	10.81
1340	WARDLOW EAST	113.23	124.55	4.28
2133	WARRENSVILLE	286.09	314.70	10.81
1353	WARSPITE	214.70	236.17	8.11
1118	WARWICK	176.11	193.72	6.65
1173	WARWICK SOUTH	197.62	217.38	7.47
2029	WASKAHIGAN	173.19	190.51	6.54

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2096	WASKAHIGAN EAST	233.35	256.69	8.82
2160	WATER VALLEY	113.23	124.55	4.28
2123	WATINO	286.09	314.70	10.81
1945	WATR1/WATR2 SUM	113.23	124.55	4.28
1570	WATTS	137.82	151.60	5.21
1021	WAYNE NORTH	139.35	153.29	5.26
1039	WAYNE-DALUM	129.66	142.63	4.90
1107	WAYNE-ROSEBUD	113.23	124.55	4.28
1585	WEASEL CREEK	260.54	286.59	9.84
1723	WEAVER LAKE	286.09	314.70	10.81
1780	WEAVER LAKE S.	286.09	314.70	10.81
2207	WEBSTER	286.09	314.70	10.81
2248	WEBSTER NORTH	286.09	314.70	10.81
1825	WELLING	248.12	272.93	9.37
2158	WEMBLEY	219.00	240.90	8.27
2120	WEST PEMBINA S.	131.75	144.93	4.98
1188	WEST VIKING	201.72	221.89	7.62
1321	WESTLOCK	286.09	314.70	10.81
3871	WESTLOCK INTERCONNECTION	286.09	314.70	10.81
1787	WHISTWOW	286.09	314.70	10.81
2701	WHITBURN EAST	253.75	279.13	9.59
1094	WHITECOURT	216.60	238.26	8.18
2075	WHITELAW	261.92	288.11	9.90
2055	WHITEMUD EAST	286.09	314.70	10.81
3917	WHITEMUD RIVER/WHITEMUD WEST SUMMARY	286.09	314.70	10.81
1345	WHITFORD	217.80	239.58	8.23
1684	WIAU LAKE	286.09	314.70	10.81
1777	WIAU LAKE SOUTH	286.09	314.70	10.81
2005	WILDCAT HILLS	113.23	124.55	4.28
1661	WILDHAY RIVER	156.60	172.26	5.92
1650	WILDUNN CREEK E	113.23	124.55	4.28
2112	WILLESDEN GR N.	113.23	124.55	4.28
2014	WILLESDEN GREEN	113.23	124.55	4.28
1428	WILLINGDON	195.69	215.26	7.39
1652	WILLOW RIVER	286.09	314.70	10.81
1759	WILLOW RIVER N	286.09	314.70	10.81

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2019	WILSON CREEK	162.14	178.35	6.13
2171	WILSON CREEK SE	163.44	179.78	6.18
1046	WIMBORNE	113.23	124.55	4.28
1234	WIMBORNE NORTH	113.23	124.55	4.28
2707	WINAGAMI LAKE	286.09	314.70	10.81
2012	WINDFALL	165.78	182.36	6.26
1577	WINEFRED RIVER	286.09	314.70	10.81
1628	WINEFRED RVR N.	286.09	314.70	10.81
1671	WINEFRED RVR S.	286.09	314.70	10.81
1670	WINEFRED RVR W.	286.09	314.70	10.81
1070	WINTERING HILLS	113.23	124.55	4.28
1104	WINTERING HLS E	113.23	124.55	4.28
2147	WITHROW	125.67	138.24	4.75
2124	WOKING	286.09	314.70	10.81
2214	WOLVERINE RIVER	286.09	314.70	10.81
1035	WOOD RIVER	202.69	222.96	7.66
3425	WOOD RVR SALES	202.46	222.71	7.65
2057	WORSLEY EAST	286.09	314.70	10.81
1342	YOUNGSTOWN	194.58	214.04	7.35
2060	ZAMA LAKE	286.09	314.70	10.81
1944	ZAMA LAKE SUMMARY	286.09	314.70	10.81

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Revised Table 6.1-3 Attachment 2

Distance Band	**Maximum Distance Between Receipt Point and Delivery Point (km)**		**FT-P Demand Rate per Month**
	From	To	($\$/10^3m^3$)
1	0	25	133.11
2	>25	50	142.71
3	>50	75	152.31
4	>75	100	161.91
5	>100	125	171.52
6	>125	150	181.12
7	>150	175	190.72
8	>175	200	200.33
9	>200	225	209.93
10	>225	250	219.53
11	>250	275	229.14
12	>275	300	238.74
13	>300	325	248.34
14	>325	350	257.95
15	>350	375	267.55
16	>375	400	277.15
17	>400	425	286.75
18	>425	450	296.36
19	>450	475	305.96
20	>475	500	315.56
21	>500		325.17

APPENDIX A: COST OF SERVICE STUDY

TransCanada

NOVA Gas Transmission Ltd.

Cost of Service Study

~~September 2003~~

REVISED February 2004

Table of Contents

1. Introduction

This report documents the findings of NGTL's second Cost of Service ("COS") Study (the "2002 COS Study") and forms part of NGTL's 2004 GRA (Phase I) Application. The changes in the methodology of calculating costs for metering service, which were used in the COS Update have been retained in this study. A more detailed explanation of this methodology change and the reasons for it can be found in section 3.1. This COS Study has clearly defined applications as outlined below and should be used in that context.

The first pages of the report provide related background information and explanations of the methodologies and rationale employed to derive the results. A series of tables follows and provides the summary numerical results of the 2002 COS Study.

1.1. Background

On July 13, 2000, the Alberta Energy and Utilities Board ("Board") denied the Alberta Consumers' request for a review and variance of the Board's Decision No. 2000-6[1]. At the same time, the Board noted that NOVA Gas Transmission Ltd. ("NGTL"), in the letter dated June 16, 2000 accompanying its submission on the review and variance application, advised that "it would, on its own initiative, be conducting a cost of service study with a view to a May 2001 completion date". Due to concurrent demands on key resources, TransCanada was unable to start the study until March 2001.

On March 13, 2001, NGTL applied to the Board for approval of the 2001-2002 Alberta System Rate Settlement ("the Settlement"). The Board approved the settlement on May 29, 2001. In Article 10 of the Settlement, Future Principles, it is stated that the parties agreed to enter into discussions and negotiations to resolve matters related to the facilities including, among other things, "the development and implementation of services that will provide operational and contractual flexibility and a rate structure that is fair and efficient for and between intra-Alberta and ex-Alberta Customers."

NGTL filed a cost of service study ("COS Study") based on 1999 data with the Board in November, 2001 and in so doing, satisfied the commitment mentioned in the first paragraph above. It was also a first step in support of Article 10 of the Settlement.

On January 20, 2003, NGTL filed with the Board Application No.1289773, the 2003 Tariff Application and a related 2003 Revenue Requirement Settlement Application, Application No. 1294603, on February 27, 2003 and amended on March 31, 2003. Included in the Tariff Application filing was an update to the COS Study. The Cost of Service Update ("COS Update") served to update the COS Study using 2001 data, to effect a change in the methodology of calculating costs for the metering service, and to eliminate ancillary services. Based on the findings of the original COS Study and the COS Update, these applications included the implementation of services that were designed to provide operational and contractual flexibility and a rate structure that is fair and efficient for and between intra-Alberta and ex-Alberta Customers.

1.2. Issues raised by the Board and interested parties

During the regulatory proceedings and subsequent decisions related to Products and Pricing and the negotiations for the 2001-2002 Alberta System Rate Settlement, a number of issues were raised that could be addressed by a cost of service study. These included:

- Improved cost accountability.

[1] Decision 2000-6 pertaining to NGTL's 1999 Products and Pricing Application was rendered on February 4, 2000.

- Lower level of cost segregation. For example, metering costs could be separated from the transmission costs. The latter could be segregated into lateral and mainline.
- Review of the services that had no toll at the time, e.g., intra-Alberta deliveries.
- Appropriateness of the use of distance of haul for allocation of costs between receipt and delivery functions.

The 2003 Tariff Settlement application embodied some of the changes outlined above. Specifically, it included a toll for intra-Alberta deliveries based upon the findings of the COS Update. In its Decision 2003-051 regarding the NGTL 2003 Revenue Requirement and Tariff Settlement Applications, with regard to a 2002 COS Study, the Board directed NGTL to:

- Complete its analysis and evaluation of the three potential changes and one alternative to the DOH methodology.
- Establish mainline and lateral costs using the two illustrative definitions included in the Original Study and any other reasonable definitions such as 12 inches or greater for the size of mainlines.
- Split the lateral pipelines into receipt and delivery.
- Disaggregate costs for receipt, export, intra-Alberta, storage and extraction metering services.
- Base the study on 2002 data.
- Include numerical results.

1.3. Objectives of the COS Study

Based on the above issues and background, the objectives of the first NGTL COS Study were:

- To improve the industry's understanding of the NGTL cost structure.
- To provide a clearer definition of the costs associated with different functions or services.[2]
- To provide information to facilitate the development and support of future principles as agreed in the Settlement.

Specifically for the 2002 COS Study the objectives are:

- To provide an update to the original COS Study using 2002 data, including numerical results.
- To determine the toll for FT-A Service in accordance with the methodology approved in Decision 2003-51.
- To update the methodologies due to the elimination of ancillary services and the aggregation of metering costs.

The 2002 COS Study does not provide and evaluate three potential changes and one alternative to the DOH methodology, split lateral pipelines into receipt and delivery, or disaggregate costs for metering services. The 2002 COS Study will be updated to include such analyses for the 2004 GRA (Phase 2) application.

1.4. What this COS Study is and what it is not

Typically, cost of service studies are done by local distribution companies. The studies spell out the costs incurred in providing different services to customers. These studies are the groundwork for and are often part of the evidence presented in a rate application. Allocations are relied upon to apportion costs fairly to all services because a significant portion of the costs may not be directly attributable to services.

[2] The services defined in this study are not the transportation services, described in NGTL's tariff, whose tolls are a product of rate design. The COS Study services could be viewed as sub-functions.

Consequently, COS studies in general and NGTL COS studies in particular are not the following:

- Rate change applications.
- Formal, "evidentiary" defense of a prospective level of regulated revenue requirement.
- Value or market-based analyses of services provided by the utility.
- 100% deterministic quantitative exercises, because of the need for allocations and, in some cases, expert judgement.
- Solutions, by way of rate design or otherwise, to all issues, commercial or otherwise, facing the utility, its customers, the regulator and interested parties.

This study is designed to meet the specific objectives defined in section 1.3 and should be viewed in that context.

1.5. The time period covered by the 2002 COS Study

This NGTL COS Study uses 2002 calendar year costs and the net book value ("NBV") of assets as of December 31, 2002 instead of a mid-year value or a 13-month weighted average.

1.6. Guiding principles

Several guiding principles were employed in the original COS Study to ensure that the study produced meaningful and useful results. The same principles were employed for the 2002 COS Study. They are as follows:

Relevance to the objectives of the study was an important principle, in particular relevance to the cost accountability objective. For example, in isolating and allocating certain cost items separately from others, this study links significant costs with the most significant cost drivers that could be identified.

Materiality of the cost items is reflected in the level of detail the data has been summarized to and presented in this report. In breaking down the costs by account, no benefit would be achieved by going to a lower level of detail than provided here. To illustrate, $2 million, although a large number by itself, represents less than 0.2% of the total 2002 costs analyzed in this study. Nevertheless, because of the first principle above, some cost items that are between $1 million and $3 million are kept separate in this study because specific cost drivers were identified for them.

Practicality of approach was used first in the identification of an allocator for cost items that have no direct relationship to the pipeline facilities themselves, e.g., Calgary Offices costs. Reasonableness, consistency across similar cost items and simplicity were criteria used in finding an appropriate allocator for these costs. Next, a practical approach was required to integrate data from different operational information systems that were not originally designed to be integrated. Only the data elements that were considered material and relevant (e.g., in terms of cost drivers) were retained. This ensured that the study was done in a cost-effective manner.

2. The cost accounts

The accounts are grouped into four major categories.

2.1. *Pipeline asset costs*

The pipeline asset accounts are the repositories of the largest components of the rate base and related costs. These costs are sometimes referred to as “direct costs” because they are a function of, or can be expressed as a function of an allocator like NBV. They include depreciation, operating return and income and capital taxes. As explained in the General and Administration (“G&A”) section below, transportation by others (“TBO”), direct maintenance and municipal taxes are also included in these pipeline asset accounts.

There are three pipeline asset accounts based on the major types of facilities that make up the pipeline system. **Compression** includes all compressor stations. This means not only the compressor units that are on site but also buildings, yard piping and other facilities that make up the stations. **Metering** includes all meter stations. Similarly to compression, this includes the meter runs themselves, buildings, yard piping, measurement automation and other facilities that make up the stations. **Pipes** include all pipelines that are in-service, other than compressors and meter stations yard pipes. Crossovers and control valves are also included in pipes.

2.2. *General Plant*

The general plant (“GP”) asset accounts contain all costs related to facilities that do not make up the physical pipeline system itself, e.g., field offices. The costs related to these assets are depreciation, operating return and income and capital taxes. The field offices also incur municipal taxes. The five GP accounts are as follows:

- General Operating Assets are compressor units, pipes and meter stations required for either emergency response or for regular maintenance on the system, e.g., pull-down compressors.
- Calgary Offices include the costs related to the Calgary Head Office (e.g., leasehold improvements).
- Field Offices, Service Centres and Vehicles include the costs related to the field offices, the service centres, the light-duty vehicles and the heavy equipment used in the field.
- Patrol is the account for the fleet of aircraft used mainly for pipeline reconnaissance and survey.
- Information Technology includes the investments in computer hardware and software.

2.3. *Working Capital*

Working capital accounts are the repositories for the funds necessary to carry out business operations. The costs related to these accounts include only operating return and income and capital taxes because these assets do not incur depreciation, municipal taxes or any of the other cost items. There are four working capital accounts. Linepack includes the cost of gas owned by NGTL in its own pipelines and used to maintain the line pressure required for the transmission of gas. Materials and supply inventory includes the cost of materials purchased primarily for use in construction, operations, or maintenance of the pipeline system facilities. Cash working capital is the amount of cash needed to allow for the time lag between the payment of ongoing operating expenses and the collection of corresponding revenues. Unamortized debt issue costs are costs, incurred by NGTL to issue long-term debt, which are recoverable from NGTL’s customers over the life of the debt.

2.4. *General and Administration*

G&A are the accounts against which general operating expenses are recorded, e.g. salaries and benefits of shared services employees. The G&A accounts are as follows:

- Information Technology is the account for all operating expenses related to the development and maintenance of NGTL’s computer systems.
- Customer Service is the account that contains all operating expenses for the functions of customer interface, gas control, operations planning and system design.

- Other departments contain the operating expenses for all other departments in NGTL, including human resources, health, safety and environment, etc.
- Corporate is the account that records NGTL's share of expenses from TransCanada's shared services. This includes legal, corporate accounting, tax, government and community relations, internal audit, etc.
- General expenses are recurring costs incurred in the conduct of business that are not department-specific. For example, this includes insurance, external legal fees, external audit fees, directors and corporate membership fees.
- Other expenses are sporadic costs incurred in the conduct of business that are not department-specific. Included in this account are uninsured losses, regulatory hearing expenses, transitional items and miscellaneous expenses.

It is important to note that a portion of the costs related to the engineering department were capitalized, due to the construction project nature of its work. Those capitalized costs are part of the rate base and therefore result in direct costs such as depreciation. The capitalized costs were not included in the G&A accounts because that would have resulted in double counting. The remainder of the engineering costs pertains to maintenance and is not capitalized. They were included in the direct maintenance costs associated with pipeline asset accounts as direct relationships exist.

The source that was used for maintenance costs already records them against specific pipeline facilities. Therefore, these costs are included in the pipeline asset accounts as direct costs.

The same is true for municipal taxes so they too have been included in pipeline asset accounts as direct costs.

Table 1 in Appendix 2 shows the list of the accounts, their value at December 31, 2002 and their total costs in 2002.

3. The methodologies

Once all accounts and 2002 costs were identified, the functionalization step could proceed. Different methodologies had to be employed, particularly for general plant, working capital accounts and G&A costs because their relationship to the pipeline facilities is not a direct one. These costs are referred to as non-direct costs in this study. Functions were identified, to which costs could be allocated and appropriate allocators were chosen.

Three major functions were identified for the NGTL pipeline system:

1. Transmission, as this is NGTL's primary function.
2. Compression, which complements the transmission function by helping to move gas through the pipeline system.
3. Metering, where custody transfer, gas measurement and related transactional functions (e.g., scheduling) are performed at each point onto and off of the system.

Functions are at a fairly high level of aggregation. To achieve a lower segregation of costs that addresses the second suggestion listed in section 1.2 and where there is relative cost stability, costs had to be allocated to a lower level of detail called services. Services are related to functions as follows:

- Transmission was split into lateral transmission and mainline transmission services, as suggested in section 1.2.
- Compression is a function that helps move gas through the pipeline. It is not an option for a customer to choose. Therefore, compression was deemed to be part of both the lateral and the mainline transmission services.

3.1. Methodology modifications

The Ancillary function provided a level of detail that did not appear to provide value to industry at this time, therefore it has not been retained in this COS Study. As a result, no costs have been allocated to ancillary services in this study. As in the COS Update, all of the costs that would have been allocated to ancillary services under the original COS Study methodology were allocated to the metering service in this study.

In the original COS Study metering costs were split according to the primary purpose of a meter station namely; receipt, border delivery, intra-Alberta delivery, storage and extraction. Due to the considerable variation in the gas flows of intra-Alberta delivery stations and the resulting cost consequences, a volatility factor was introduced and intra-Alberta stations were grouped into four volatility categories. In the COS Update it was determined that the flow variation of intra-Alberta delivery stations not only occurred between stations, but also from one year to the next. Stations in the lowest grouping in one year, may fall into the highest grouping the next year. In this study metering costs were retained at the functional level as:

- a detailed segmentation for storage and extraction did not appear to be required by industry at this time, and
- by utilizing a system average cost to meter gas, volatility from year to year and between different groupings of stations would be reduced, eliminating the need to develop mechanisms such as the volatility factor thus reducing the time and effort required to produce the analysis.

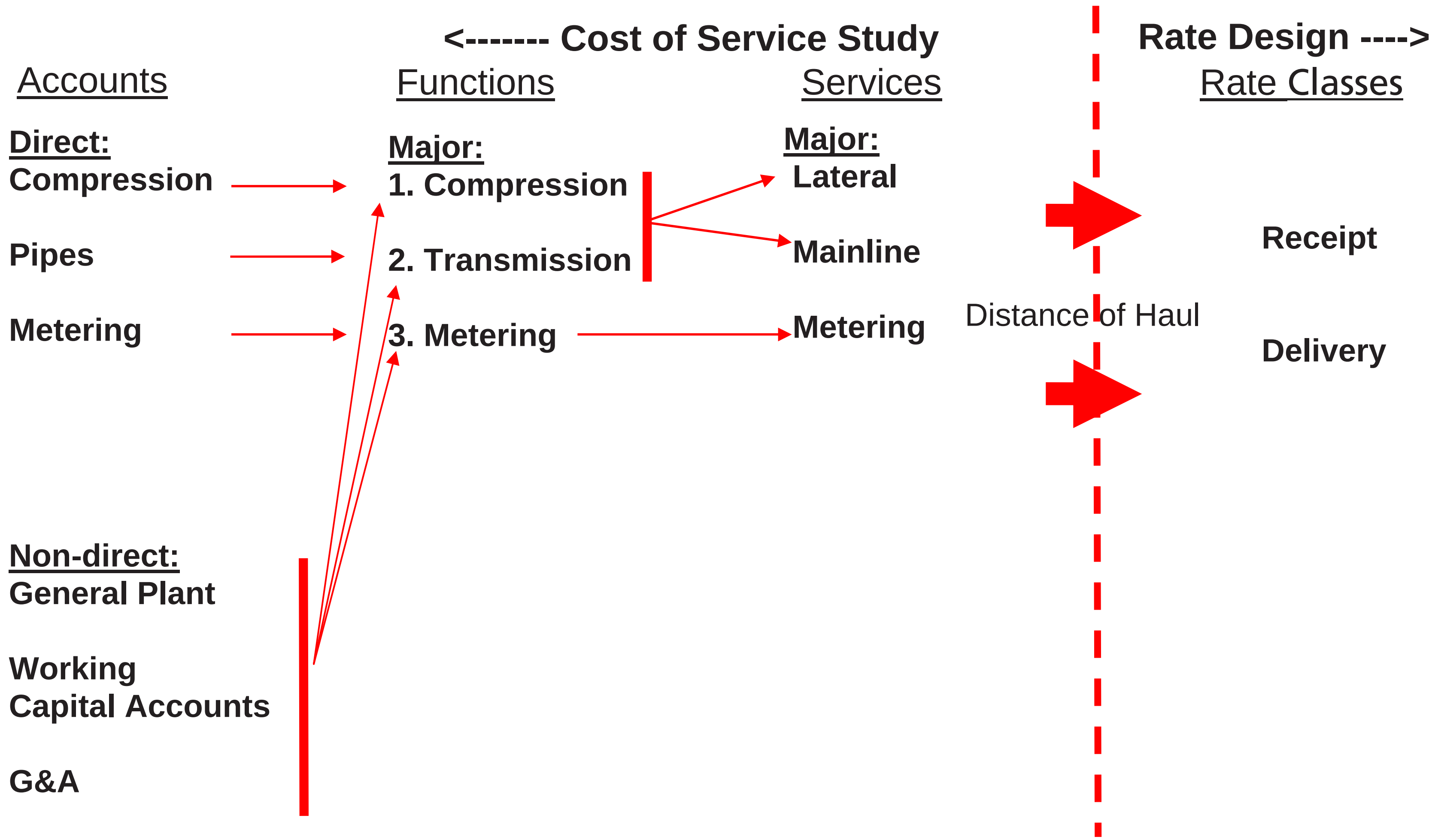
Table 5 outlining the calculation of the average unit cost per Mcf for the metering services has been added to the study. As was the case in the COS Update, the metering costs do not contain any costs for pipe dedicated to storage and extraction. The costs for such pipe have been included in the transmission costs.

The methodology changes incorporated in this COS Study serve to simplify the structure and the tables containing the results of the study.

Diagram 1 on the following page illustrates the functionalization and allocation processes that were followed in the 2002 COS Study.

Diagram 1

Overview of Cost Allocations



3.2. Functionalization

There are two major steps in the functionalization process:

- Assignment of pipeline asset costs to the compression, metering and transmission functions.
- Allocation of G&A costs and other non-direct costs to the compression, metering and transmission functions.

As this COS Study does not include ancillary services as a separate function, all costs that were allocated to these services in the original COS Study have been allocated to the metering function in this COS Study. The rationale for this allocation was set out in section 3.1.2 of the original COS Study report which stated the allocation of costs to ancillary services reflected "…the fact that a large portion of the Customer Service function is to manage the relationship with customers and the day-to-day transactions related to accounts, e.g. contract renewals, transfers and assignments. It also reflects the fact that a large portion of information technology costs is in support of the Customer Service department because it uses some of the most critical and largest computer applications in NGTL." As customers contract at meter stations, it is logical that day to day transactions and related costs should be allocated to the metering function.

3.2.1. Assignment of pipeline asset costs

Direct "assignment" is the accurate term to use here rather than allocation, because the data was collected against the specific facilities that provide those functions (or the entire pool of facilities in a function, in the case of TBO costs). Therefore the relationship is a direct one instead of being based on a formula, except for the following:

- The Foothills' Alberta TBO costs were kept as a lump sum and assigned to mainline transmission only while the remainder of the TBO costs was allocated to all of the pipes in the system based on distance, for simplicity and materiality's sake.
- A portion (about 36%) of the maintenance operating expenses was available only at an aggregate level. Upon investigation, it was determined that those expenses were attributable to maintenance activities related to meter stations and pipelines. Those costs were therefore allocated based on the maintenance cost split percentages for those two groups of facilities (see "Field Offices, Service Centres and Vehicles costs" in section 3.2.2 below).

See Tables 2-A and 2-B in Appendix 2 for the results of the functionalization of pipeline asset costs.

3.2.2. Allocation of non-direct costs to major functions

The non-direct costs were allocated to the compression, metering and transmission functions as follows.

General plant costs (see Tables 3-A and 3-B in Appendix 2)**:**

- General Operating Assets costs were allocated according to the major function of the underlying assets, i.e. compressor costs to compression, pipe costs to transmission and meter stations to metering.
- Calgary Offices costs were allocated by NBV.
- Field Offices, Service Centres and Vehicles costs were allocated to compression, metering and transmission because they support the maintenance of the pipeline system. The following average percentage splits of annual maintenance costs were used as allocators[3]:

[3] These are historical averages based on actual annual maintenance costs.

   - 50% to compression
   - 35% to metering
   - 15% to pipes.
- Patrol was allocated to transmission only.
- 46% of Information technology asset account costs were determined to be associated with day to day account transactions and as such were allocated directly to the metering function. The remaining 54% of these costs were allocated to the compression and transmission function using NBV.

The working capital account costs (see Tables 3-A and 3-B in Appendix 2)**:**
- Linepack was allocated to transmission only.
- Materials and supplies inventory costs were allocated based on the following percentage splits, provided by field experts:
   - 73% to compression
   - 8% to metering
   - 19% to transmission.
- Cash working capital and unamortized debt issue costs were allocated by NBV.

G&A costs (see Tables 3-A and 3-B in Appendix 2[4]):
- Other departments, Corporate, General Expenses, and Other expenses were allocated using the NBV of the facilities providing the three major functions. Based on data in NGTL's accounting system, 46% of the Information Technology G&A costs were determined to be associated with day to day account transactions and as such were allocated directly to the metering function. The remaining 54% of Information Technology G&A costs were allocated using NBV of the facilities providing the three major functions.
- 56% of Customer Service costs went directly to metering, the remaining 44% was allocated using NBV. The latter costs represent expenses incurred by the system design and operations functions of Customer Service. Therefore, it was appropriate to allocate them to all pipeline facilities because those functions impact the entire system.

3.3. Summarization by services

Once the functionalization step was complete, it was possible to take the costs allocated to each major function and allocate such costs to the individual pipeline facilities providing those functions. This was done as follows:
- Direct pipeline asset costs were assigned to specific compressor stations, meter stations and pipes ("the units") based on a cross-reference table between the account numbers in the fixed asset database and the units. See Diagram 2 on page 13 for an overview of the assignment of direct pipeline asset costs.
- All non-direct costs were allocated as follows:
   - Compression to individual compressor stations using power rating as the allocator.
   - Transmission to individual pipes using distance.
   - Metering to individual meter stations using the total number of meter stations.

  See Diagram 3 on page 14 for an overview of the allocations of non-direct costs.

[4] As in the 2001 COS Update, the Functionalized general plant working capital and G&A account costs have been combined into one table.

The above steps brought all costs down to the individual units (pipes, compressor stations, and meter stations). Summarization to services could then proceed by grouping the units by the major services they support. This was done as follows:

- Compression was not retained as a service. Therefore the total compression costs had to be allocated to pipes using the power required to move gas through each piece of pipe, under standard operating conditions.
- Lateral costs were calculated by grouping all pipes that were labelled as lateral in the mainline/lateral definition[5].
- Similarly, mainline costs were calculated by grouping all mainline pipes, including the TBO costs for Foothills' Alberta system[6].
- Metering costs were calculated by grouping all meter stations.

The results of the summarization step are shown in Tables 4-A and 4-B in Appendix 2, while Tables 6-A and 6-B give summary statistics pertaining to the NGTL system in 2002.

[5] Two illustrative definitions of mainline were used: one was functional in nature and the other based on physical size. See Appendix 1 for more detailed definitions and maps.

Diagram 2

Step 1: Assignment of Direct Costs

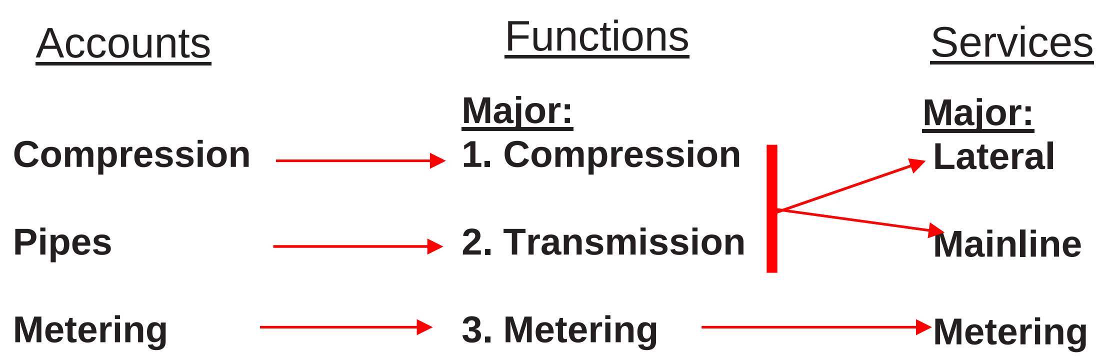
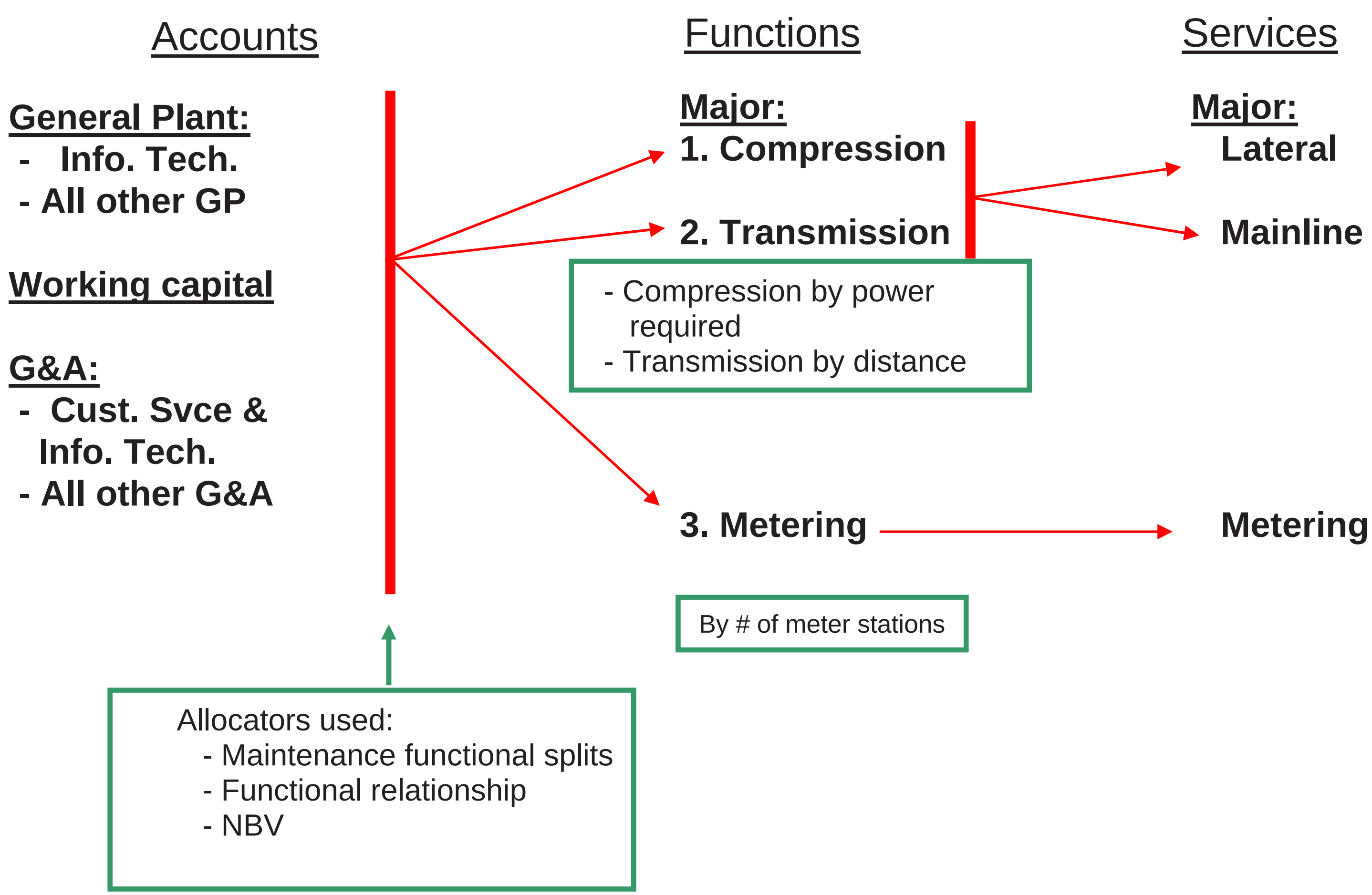


Diagram 3

Step ~~3~~2: Allocation of Non-Direct Costs



4. Appendix 1 - The mainline definitions and maps

Definition A: Functional

A functional approach was used to define "mainline". Mainline assets were designated as the facilities which are most aligned with a continental North American pipeline transmission function while the facilities which are most aligned with local gas aggregation were designated as lateral assets. The mainline includes the following facilities:

1. All pipelines of NPS 24 and greater, excluding short segments greater than or equal to NPS 24 used for river crossings of lines less than NPS 24.

2. All pipelines less than NPS 24 that are in the right-of-way (one mile radius) of pipe with a diameter of NPS 24 and greater (defined in point 1 above).

3. All pipes that connect to the transmission systems outside Alberta:
   a) Gordondale (Duke)
   b) A/BC (TransCanada B.C. System)
   c) Alberta/Montana (Montana Power)
   d) McNeill (Foothills Saskatchewan)
   e) Empress (TransCanada Mainline)
   f) Cold Lake (TransGas)

4. Select crossovers that are required for operational flexibility:
   a) Hidden Lake Compressor to Meikle River Compressor
   b) Saddle Hills Compressor to East of Spirit River Compressor
   c) Paul Lake Compressor to North of Swartz Creek Compressor
   d) Westerose Meter Station to South of Bingley Meter Station

5. All pipes connecting existing storage locations:
   a) Demmit
   b) January Creek
   c) Crossfield East
   d) Carbon
   e) Severn Creek
   f) AECO C

6. All existing pipes in the proposed Northwest Mainline corridor, south of Keppler Creek meter station to Weaver Lake South meter station

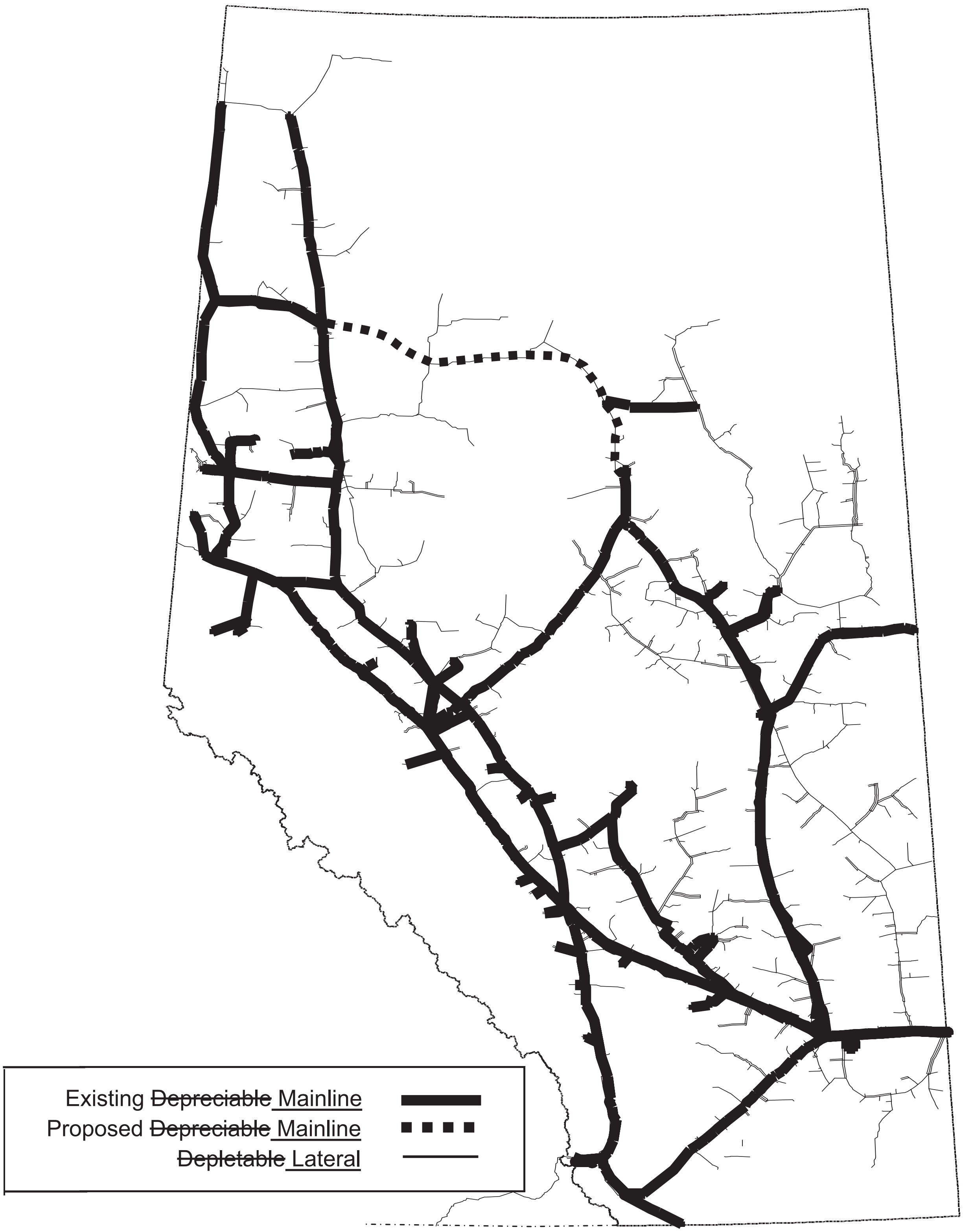
7. Other pipes:
   a) Zama Lake Meter Station to Meikle River Compressor Station
   b) Field Lake Compressor Station to Hanmore Lake Compressor Station
   c) Pipes between Mainline and Simmons/Albersun at Atmore
   d) Connections to 41 additional receipt stations

Definition B: Physical Size

In this definition, only the first criterion of definition A was considered, i.e. all pipelines of NPS 24 and greater, excluding short segments greater than or equal to NPS 24 used for river crossings of lines less than NPS 24. In this definition, only the storage facilities at January Creek, Crossfield East and AECO C are in the mainline area because they are the only storage facilities serviced by pipes that are at least 24 inches in diameter.

Appendix 1 (cont'd)

The Functional Mainline (Definition A)



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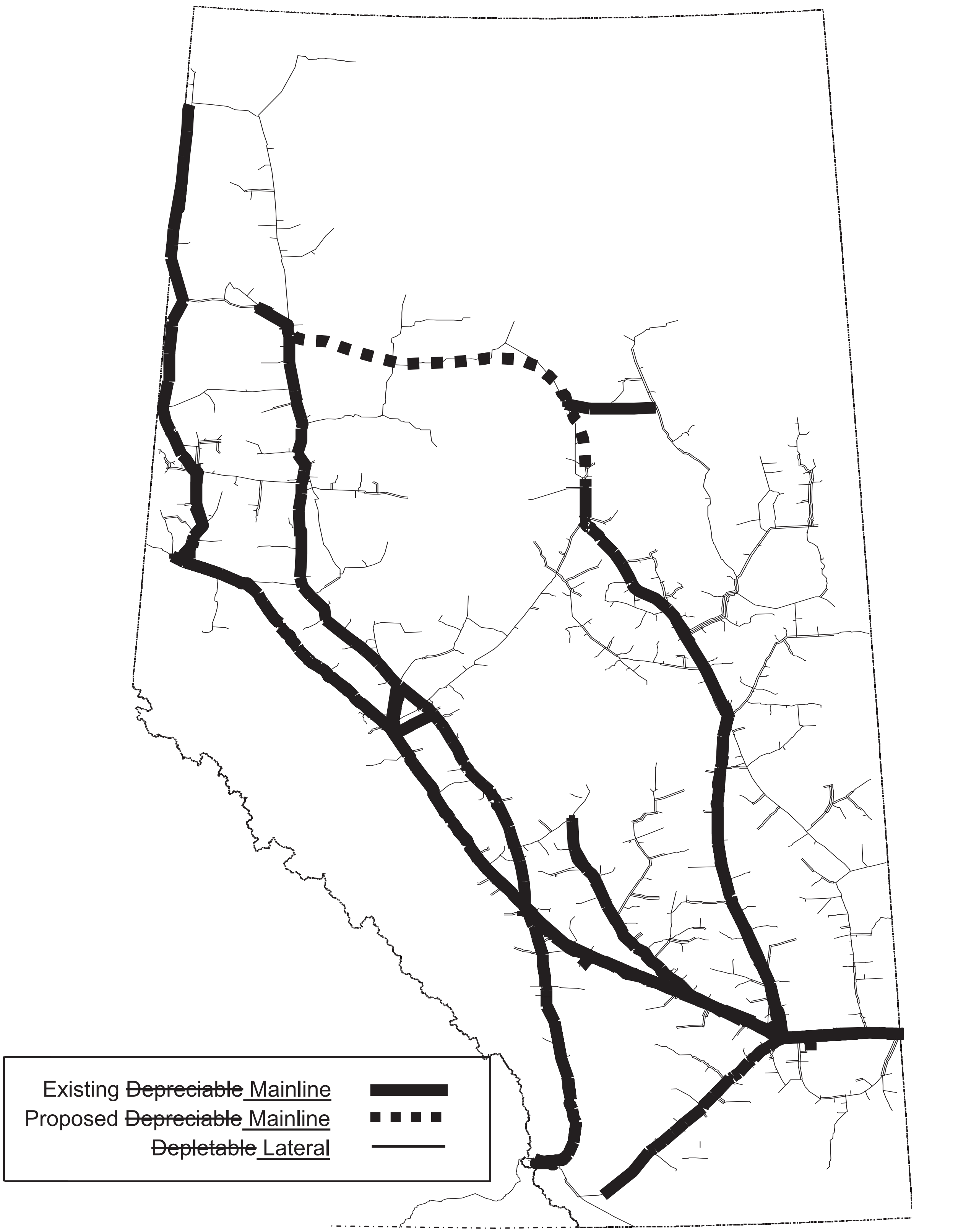
Appendix 1 (cont'd)

The Physical Size Mainline (Definition B)



5. Appendix 2 - Summary numerical tables

NOTE: Some of the numbers in the following tables may appear to not add up due to rounding.

Revised Table 1
List of accounts, 2002 value and total 2002 costs
($ Million)

All figures are in million $

	Value (1) at Dec. 31, 2002		Final 2002 costs	
Compression	967		~~266.3~~	254.4
Metering	351		~~84.9~~	93.3
Pipes	3,208		~~735.2~~	738.7
Pipeline assets total	**4,526**		**1,086.4**	
General Operating Assets	~~40~~	48	~~11.9~~	14.3
Calgary Offices	~~60~~	52	~~18.6~~	16.1
Field/Service Centres, Vehicles	87		25.7	
Patrol	2		0.5	
Information Technology	151		44.2	
General plant total	**339**		**100.8**	
Cash Working Capital	173		23.5	
Material & Supplies Inventory	31		4.1	
Linepack Gas	26		3.5	
Unamortized Debt Issue Costs	33		4.4	
Working capital total	**262**		**35.6**	
Information Technology	-		24.9	
Customer Service	-		15.6	
Other departments	-		14.7	
General Expenses	-		58.2	
Other expenses (2)	-		7.6	
G&A total	**0.0**		**121.0**	
Grand Total	**5,127**		**1,343.8**	

(1) For pipeline and general plant assets, this is the net book value (NBV).
(2) Include regulatory hearing costs, uninsured losses, transitional items and miscellaneous expenses.

Appendix 2 (cont'd)

Table 2-A
Functionalized Pipeline Asset Direct Costs
Functional Mainline Definition
($ Million)

2002 Study

	Compression	Transmission		Metering	Total
Direct Costs		Mainline	Lateral		
Operating Return	95.8	243.6	74.2	34.8	**448.5**
Depreciation	69.5	116.6	39.1	14.3	**239.5**
Municipal Tax	4.5	42.6	14.7	2.0	**63.9**
Income Tax	35.0	88.9	27.1	12.7	**163.7**
TBO	-	79.2	0.0	-	**79.2**
Maintenance	49.5	6.1	6.6	29.5	**91.7**
Total Direct Costs	**254.4**	**576.9**	**161.8**	**93.3**	**1,086.4**

Appendix 2 (cont'd)

Table 2-B
Functionalized pipeline asset direct costs
Physical Size Mainline Definition
($ Million)

2002 Study

	Compression	Transmission		Metering	Total
Direct Costs		Mainline	Lateral		
Operating Return	95.8	205.5	112.4	34.8	**448.5**
Depreciation	69.5	95.0	60.7	14.3	**239.5**
Municipal Tax	4.5	33.8	23.5	2.0	**63.9**
Income Tax	35.0	75.0	41.0	12.7	**163.7**
TBO	-	79.2	0.0	-	**79.2**
Maintenance	49.5	3.6	9.1	29.5	**91.7**
Total Direct Costs	**254.4**	**492.0**	**246.6**	**93.3**	**1,086.4**

Appendix 2 (cont'd)

Table 3-A

Functionalized general plant, working capital and G&A account costs
Functional Mainline Definition
($ Million)

2002 Study

	Compression	Transmission		Metering	Total
General Plant, Working Capital and G&A[1]		Mainline	Lateral		
General Operating Assets	9.0	1.3	1.4	2.7	14.3
Calgary Offices	3.4	5.6	5.9	1.3	16.1
Field/Service Centres, Vehicles	12.8	1.9	2.0	9.0	25.7
Patrol	-	0.2	0.2	-	0.5
Information Technology	5.1	8.2	8.7	22.3	44.2
General plant total	**30.4**	**17.1**	**18.1**	**35.2**	**100.8**
Cash Working Capital	5.0	8.1	8.6	1.8	23.5
Material & Supplies Inventory	3.0	0.4	0.4	0.3	4.1
Linepack Gas	-	1.7	1.8	-	3.5
Unamortized Debt Issue Costs	0.9	1.5	1.6	0.3	4.4
Working capital total	**9.0**	**11.7**	**12.4**	**2.5**	**35.6**
Information Technology	2.9	4.6	4.9	12.5	24.9
Customer Service	1.5	2.4	2.5	9.3	15.6
Other Departments	3.1	5.1	5.4	1.1	14.7
General Expenses[2]	12.4	20.0	21.2	4.5	58.2
Other Expenses	1.6	2.6	2.8	0.6	7.6
G&A total	**21.5**	**34.7**	**36.7**	**28.0**	**121.0**
Total General plant & Working capital	**60.9**	**63.5**	**67.2**	**65.7**	**257.4**

Allocated amounts less than $100,000 show up here as 0.0 due to rounding.
A dash ("-") means the cost item is not applicable to the function.
(1) G&A costs were in table 4-A in the 1999 COS Study.
(2) This combines the two items called General Expenses and Corporate in the 1999 COS Study.

Appendix 2 (cont'd)

Table 3-B

Functionalized general plant, working capital and G&A account costs
Physical Size Mainline Definition
($ Million)

2002 Study

General Plant, Working Capital and G&A[(1)]	Compression	Transmission		Metering	Total
		Mainline	Lateral		
General Operating Assets	9.0	0.8	1.9	2.7	14.3
Calgary Offices	3.4	3.4	8.0	1.3	16.1
Field/Service Centers, Vehicles	12.8	1.1	2.7	9.0	25.7
Patrol	-	0.1	0.3	-	0.5
Information Technology	5.1	5.0	11.9	22.3	44.2
General plant total	**30.4**	**10.5**	**24.8**	**35.2**	**100.8**
Cash Working Capital	5.0	4.9	11.7	1.8	23.5
Material & Supplies Inventory	3.0	0.2	0.6	0.3	4.1
Linepack Gas	-	1.0	2.5	-	3.5
Unamortized Debt Issue Costs	0.9	0.9	2.2	0.3	4.4
Working capital total	**9.0**	**7.1**	**16.9**	**2.5**	**35.6**
Information Technology	2.9	2.8	6.7	12.5	24.9
Customer Service	1.5	1.4	3.4	9.3	15.6
Other Departments	3.1	3.1	7.3	1.1	14.7
General Expenses[(2)]	12.4	12.2	29.0	4.5	58.2
Other Expenses	1.6	1.6	3.8	0.6	7.6
G&A total	**21.5**	**21.2**	**50.2**	**28.0**	**121.0**
Total General plant & Working capital	**60.9**	**38.8**	**92.0**	**65.7**	**257.4**

Allocated amounts less than $100,000 show up here as 0.0 due to rounding.
A dash ("-") means the cost item is not applicable to the function.
(1) G&A costs were in table 4-A in the 1999 COS Study.
(2) This combines the two items called General Expenses and Corporate in the 1999 COS Study.

Appendix 2 (cont'd)

Table 4-A
(Table 5-A in 1999 COS Study report)
Summarized costs by services
Functional Mainline Definition
($ Million)

2002 Study

	Direct Costs	Gen. Plant, Working Capital and G&A	Total Costs by Function	Allocated Compression	Total Costs by Service
Compression	254.4	60.9	315.3	-315.3	**0.0**
Mainline	576.9	63.5	640.4	290.3	**930.6**
Lateral	161.8	67.2	229.0	25.0	**254.1**
Metering	93.3	65.7	159.1	0.0	**159.1**
Totals	**1,086.4**	**257.4**	**1,343.8**	**0.0**	**1,343.8**

Appendix 2 (cont'd)

Table 4-B
(was table 5-B in 1999 COS Study report)
Summarized costs by services
Physical Size Mainline Definition
($ Million)

2002 Study

	Direct Costs	Gen. Plant, Working Capital and G&A	Total Costs by Function	Allocated Compression	Total Costs by Service
Compression	254.4	60.9	315.3	-315.3	**0.0**
Mainline	492.0	38.8	530.8	266.7	**797.5**
Lateral	246.6	92.0	338.6	48.6	**387.2**
Metering	93.3	65.7	159.1	0.0	**159.1**
Totals	**1,086.4**	**257.4**	**1,343.8**	**0.0**	**1,343.8**

Appendix 2 (cont'd)
Table 5
Summary Statistics
Calculation of Average Unit Cost per Mcf for the Metering Service

$P = C \div (V * D)$

Where

P is the unit cost in dollars per Mcf

C is the total of all costs assigned or allocated to the metering service. This total is the second last figure in the rightmost column of tables 4-A and 4-B, except that it is expressed in dollars instead of millions of dollars.

V is the average commodity volume at all meter stations on the Alberta system, as shown on tables 6-A and 6-B, except that it is expressed in Mcf/day instead of MMcf/day.

D is the number of days in the year. This converts the average volume ("V") to the total commodity volume for the year.

For 2002, the unit cost per Mcf for the metering service was as follows:

P = \$159,064,609 ÷ (23,696,172 Mcf/day * 365 days)

Therefore, P = \$0.0184 / Mcf

Appendix 2 (cont'd)

Table 6-A
Summary Statistics
Functional Mainline Definition

	2002 Data				
	Length of Pipe (Miles) (4)	**Power (MW)**	**Average Volume (MMcf/d)**	**Meter Station Count**	**Mcf-miles**
Compression	-	969	-	-	-
Mainline (1)	6,929	-	11,261	-	1,140,828,553,534
Lateral (2)	7,174	-	5,659	-	60,745,007,487
Metering (3)	-	-	23,696	1,109	-
Totals	**14,103**	**969**		**1,109**	**1,201,573,561,020**

(1) The volume for mainline is the sum of the net lateral receipt volumes and the mainline receipt volumes. Net lateral receipt volumes are the lateral receipt volumes minus the intra-Alberta delivery volumes in the lateral area.
(2) The lateral volumes are the volumes from receipt stations in the lateral area.
(3) Metering volumes include receipt, intra & border delivery, storage and extraction volumes. Extraction volumes are the volumes removed from the system at extraction plants, not the volumes delivered to the extraction plants inlets or the shrinkage volumes used to balance the energy removed by the extraction plants. Storage volumes are the sum of net physical volumes both into and out of storage.
(4) In 2002, the pipes related to storage and extraction are included in the mainline definition.

Appendix 2 (cont'd)

Table 6-B
Summary Statistics
Physical Size Mainline Definition

2002 Data

	Length of Pipe (Miles) [4]	Power (MW)	Average Volume (MMcf/d)	Meter Station Count	Mcf-miles
Compression	-	969	-	-	-
Mainline [1]	4,242	-	11,030	-	1,071,445,401,595
Lateral [2]	9,860	-	8,578	-	130,128,159,426
Metering [3]	-	-	23,696	1,109	-
Totals	**14,103**	**969**		**1,109**	**1,201,573,561,020**

(1) The volume for mainline is the sum of the net lateral receipt volumes and the mainline receipt volumes. Net lateral receipt volumes are the lateral receipt volumes minus the intra-Alberta delivery volumes in the lateral area.

(2) The lateral volumes are the volumes from receipt stations in the lateral area.

(3) Metering volumes include receipt, intra & border delivery, storage and extraction volumes. Extraction volumes are the volumes removed from the system at extraction plants, not the volumes delivered to the extraction plants inlets or the shrinkage volumes used to balance the energy removed by the extraction plants. Storage volumes are the sum of net physical volumes both into and out of storage.

(4) In 2002, the pipes related to storage and extraction are included in the mainline definition.