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THE DEVELOPMENT POTENTIAL OF COALBED METHANE IN THE WARRIOR COAL BASIN OF ALABAMA

Chapters 1, 2 and 3

May 1984

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Morgantown, West Virginia

By
The University of Alabama
University, Alabama

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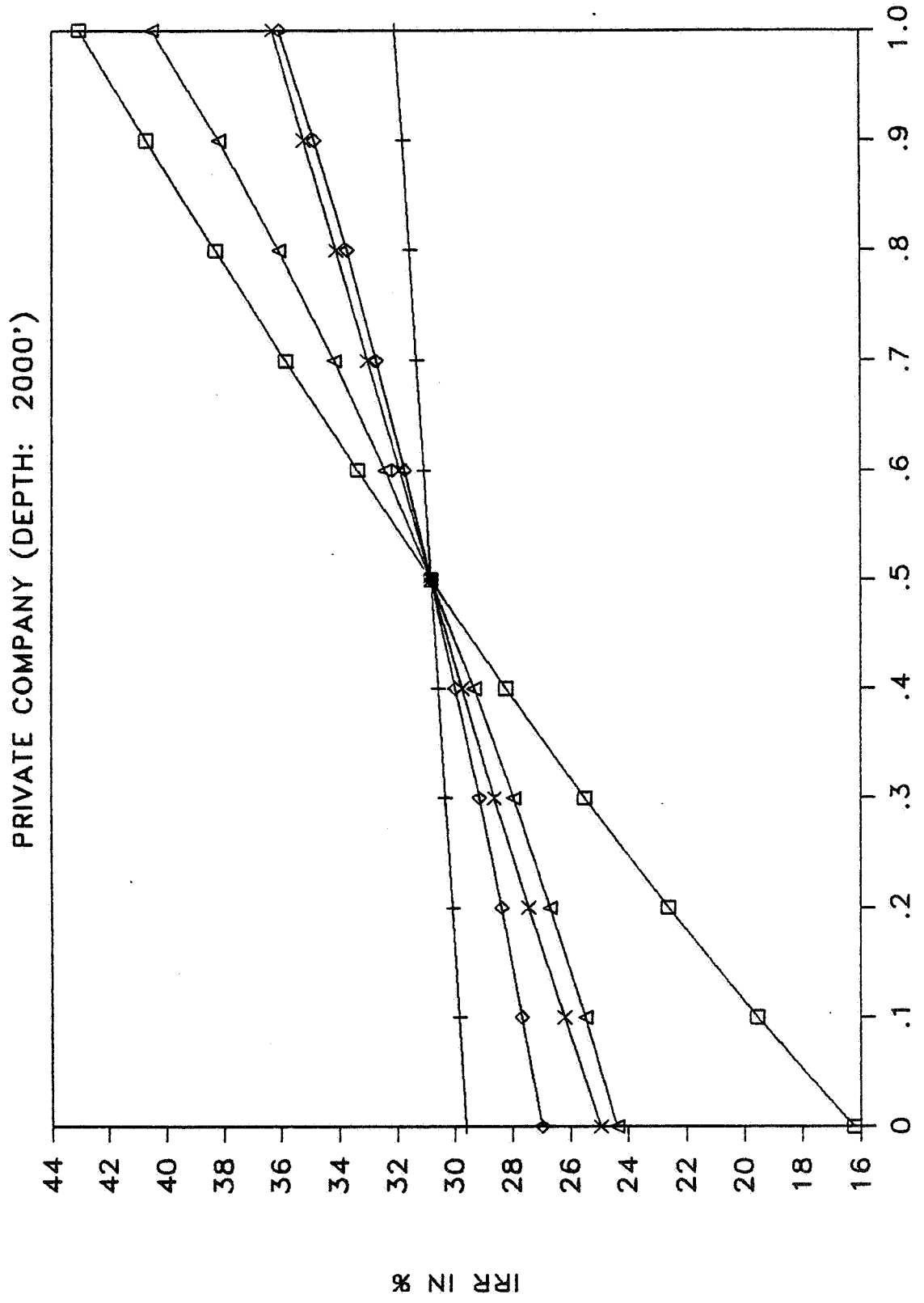

Figure 3-7 Graphical Representation of Sensitivity in IRR in % to Changes in Components of Cash Flow from Worst to Best Possible Scenarios, Private Company

TABLE 3-25

PRIVATE COMPANY

DEPTH: 3000

SENSITIVITY IN IRR IN % TO CHANGES IN COMPONENTS OF CASH FLOW FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	14.21	17.39	20.31	23.05	25.65	28.09	30.46	32.78	35.04	37.26	39.45
PRICE SERIES	26.93	27.16	27.39	27.63	27.86	28.09	28.32	28.55	28.78	29.01	29.24
TANGIBLE COSTS	24.48	25.16	25.85	26.56	27.30	28.09	28.92	29.80	30.74	31.73	32.80
INTANGIBLE COSTS	22.30	23.31	24.39	25.54	26.77	28.09	29.50	31.03	31.68	34.48	36.45
ANNUAL OPERATING COSTS	22.51	23.72	24.86	26.00	27.07	28.09	29.10	30.11	31.12	32.12	33.12

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-26

PRIVATE COMPANY

DEPTH: 1000

SENSITIVITY IN NPV (15% DISCOUNT RATE)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*
IN $1000

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	40	80	119	157	195	233	271	309	347	385	423
PRICE SERIES	216	220	223	226	230	233	237	240	243	247	250
TANGIBLE COSTS	205	211	216	222	228	233	239	244	250	255	261
INTANGIBLE COSTS	171	184	196	208	221	233	246	258	270	283	295
ANNUAL OPERATING COSTS	155	172	188	203	218	233	248	263	278	293	309

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-27

PRIVATE COMPANY

DEPTH: 2000

SENSITIVITY IN NPV (15% DISCOUNT RATE)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*
IN $1000

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	15	56	95	135	173	211	248	286	324	362	400
PRICE SERIES	193	197	200	204	207	211	214	217	221	224	228
TANGIBLE COSTS	180	186	192	198	204	211	217	223	229	235	241
INTANGIBLE COSTS	147	160	172	185	198	211	223	236	249	262	274
ANNUAL OPERATING COSTS	132	148	164	180	195	211	226	241	256	271	286

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

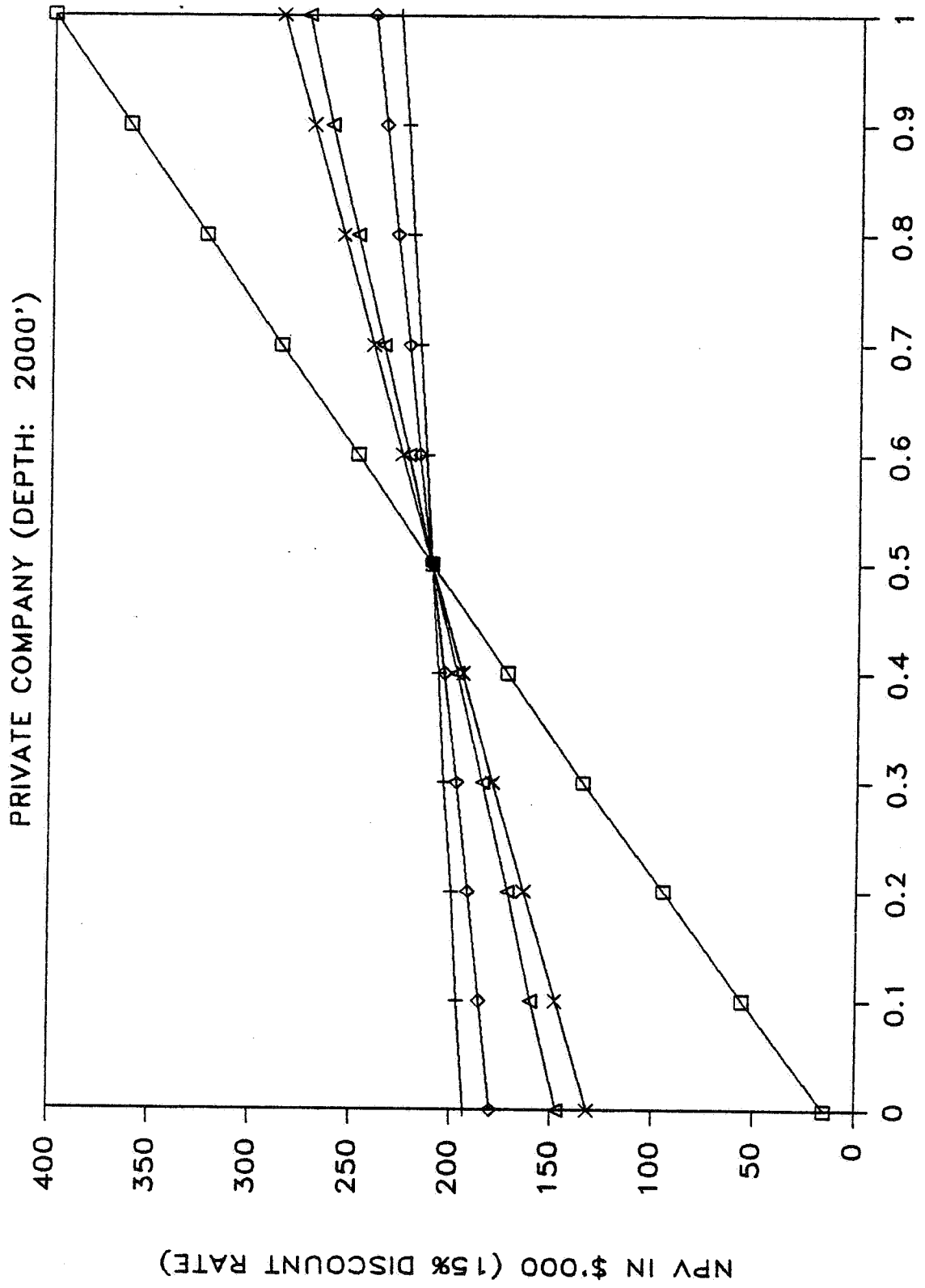

Figure 3-8 Graphical Representation of Sensitivity in NPV (15% Discount Rate) to Changes in Components of Cash Flow from Worst to Best Possible Scenarios in $1000, Private Company

TABLE 3-28

PRIVATE COMPANY

DEPTH: 3000

SENSITIVITY IN NPV (15% DISCOUNT RATE)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*
IN $1000

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	(102)	32	72	111	150	188	226	264	302	339	377
PRICE SERIES	171	174	178	181	184	188	191	195	198	202	205
TANGIBLE COSTS	154	161	168	175	181	188	195	201	108	214	221
INTANGIBLE COSTS	122	135	148	162	175	188	201	214	227	240	254
ANNUAL OPERATING COSTS	107	124	141	157	173	188	203	218	233	248	263

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-29

PRIVATE COMPANY

DEPTH: 1000

SENSITIVITY IN PAYBACK (YEARS)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	4.78	4.30	3.91	3.59	3.33	3.10	2.90	2.72	2.56	2.42	2.29
PRICE SERIES	3.23	3.20	3.18	3.15	3.13	3.10	3.08	3.06	3.03	3.01	2.98
TANGIBLE COSTS	3.41	3.35	3.29	3.23	3.17	3.10	3.04	2.97	2.89	2.82	2.74
INTANGIBLE COSTS	3.76	3.63	3.50	3.37	3.24	3.10	2.97	2.82	2.67	2.53	2.38
ANNUAL OPERATING COSTS	3.73	3.58	3.44	3.32	3.21	3.10	3.01	2.91	2.81	2.73	2.64

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-30

PRIVATE COMPANY

DEPTH: 2000

SENSITIVITY IN PAYBACK (YEARS)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	5.15	4.60	4.21	3.87	3.59	3.35	3.15	2.96	2.79	2.64	2.50
PRICE SERIES	3.48	3.45	3.43	3.40	3.38	3.35	3.33	3.30	3.28	3.25	3.23
TANGIBLE COSTS	3.56	3.60	3.54	3.48	3.42	3.35	3.28	3.21	3.14	3.07	3.00
INTANGIBLE COSTS	4.02	3.88	3.75	3.62	3.48	3.35	3.22	3.08	2.94	2.80	2.65
ANNUAL OPERATING COSTS	4.02	3.86	3.71	3.58	3.47	3.35	3.25	3.15	3.06	2.97	2.88

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

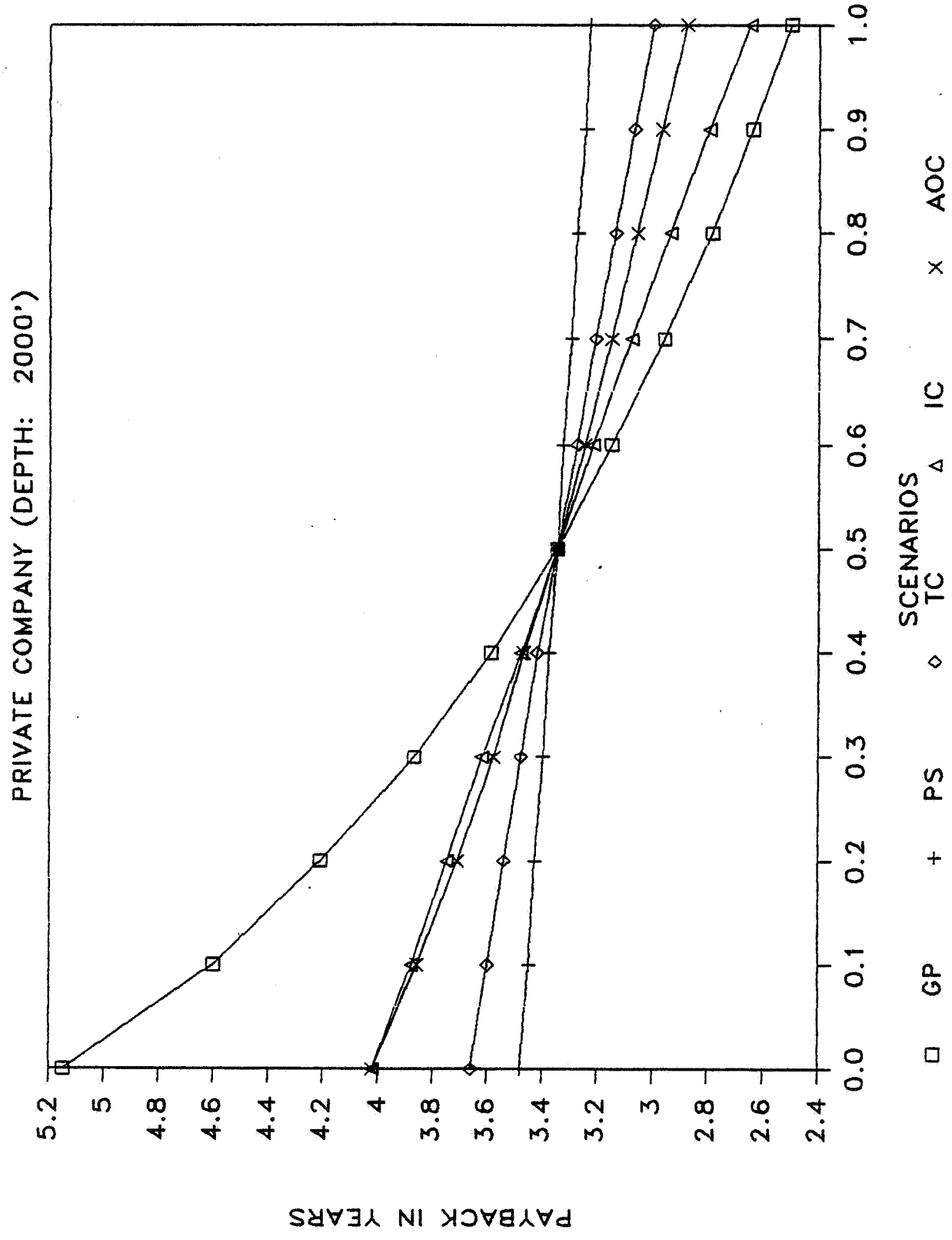

Figure 3-9 Graphical Representation of Sensitivity in Payback (Years) to Changes in Components of Cash Flow from Worst to Best Possible Scenarios, Private Company

TABLE 3-31

PRIVATE COMPANY

DEPTH: 3000

SENSITIVITY IN PAYBACK (YEARS)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	5.55	4.91	4.48	4.13	3.84	3.59	3.37	3.18	3.01	2.85	2.71
PRICE SERIES	3.72	3.69	3.67	3.64	3.61	3.59	3.56	3.54	3.51	3.49	3.46
TANGIBLE COSTS	3.92	3.85	3.78	3.72	3.65	3.59	3.52	3.45	3.38	3.30	3.23
INTANGIBLE COSTS	4.24	4.12	3.99	3.86	3.72	3.59	3.45	3.32	3.18	3.05	2.90
ANNUAL OPERATING COSTS	4.28	4.12	3.98	3.83	3.70	3.59	3.48	3.38	3.28	3.19	3.11

*When one of the five major components of cash flow is allowed to vary from worst to best possible scenarios, the other four major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-32

PUBLIC COMPANY

DEPTH: 1000'

SENSITIVITY IN IRR IN %
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	25.83	30.57	35.09	39.48	43.78	48.01	52.18	56.31	60.41	64.48	68.53
PRICE SERIES	45.83	46.27	46.70	47.14	47.57	48.01	48.45	48.89	49.33	49.77	50.21
INVESTMENT	34.13	36.28	38.68	41.38	44.46	48.01	52.16	57.10	63.11	70.63	80.38
ANNUAL OPERATING COSTS	37.26	39.39	41.53	43.69	45.84	48.01	50.19	52.37	54.57	56.78	58.99

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-33

PUBLIC COMPANY

DEPTH: 2000'

SENSITIVITY IN IRR IN %
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	22.88	27.23	31.41	35.45	39.40	43.26	47.06	50.81	54.52	58.21	61.86
PRICE SERIES	41.31	41.70	42.09	42.48	42.87	43.26	43.65	44.04	44.49	44.83	45.72
INVESTMENT	30.99	32.92	35.06	37.46	40.17	43.26	46.83	51.03	56.05	62.21	69.98
ANNUAL OPERATING COSTS	33.54	35.47	37.41	39.35	41.30	43.26	45.20	47.18	49.16	51.13	53.12

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-34

PUBLIC COMPANY DEPTH: 3000'

SENSITIVITY IN IRR IN %
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	20.34	24.43	28.33	32.09	35.75	39.33	42.83	46.29	49.70	53.07	56.42
PRICE SERIES	37.55	37.90	38.26	38.61	38.97	39.33	39.68	40.04	40.40	40.75	41.11
INVESTMENT	28.29	30.05	31.99	34.16	36.58	39.33	42.47	46.13	50.49	55.65	62.09
ANNUAL OPERATING COSTS	30.42	32.19	33.98	35.76	37.54	39.33	41.11	42.91	44.70	46.50	48.30

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-35

PUBLIC COMPANY

DEPTH: 1000'

SENSITIVITY IN PAYBACK (YEARS)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	4.19	3.66	3.24	2.91	2.61	2.38	2.19	2.02	1.88	1.75	1.64
PRICE SERIES	2.51	2.48	2.46	2.43	2.40	2.38	2.35	2.33	2.31	2.29	2.26
INVESTMENT	3.76	3.10	2.93	2.75	2.56	2.38	2.20	2.01	1.81	1.61	1.41
ANNUAL OPERATING COSTS	3.16	2.99	2.81	2.65	2.51	2.38	2.26	2.16	2.06	1.97	1.89

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-36

PUBLIC COMPANY DEPTH: 2000'

SENSITIVITY IN PAYBACK (YEARS)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	4.55	4.01	3.55	3.19	2.89	2.63	2.42	2.23	2.08	1.95	1.82
PRICE SERIES	2.78	2.75	2.72	2.69	2.66	2.63	2.60	2.58	2.55	2.52	2.50
INVESTMENT	3.53	3.36	3.19	3.02	2.83	2.63	2.44	2.24	2.05	1.84	1.63
ANNUAL OPERATING COSTS	3.45	3.26	3.09	2.93	2.77	2.63	2.50	2.39	2.28	2.18	2.10

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-37

PUBLIC COMPANY

DEPTH: 3000'

SENSITIVITY IN PAYBACK (YEARS)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	4.91	4.32	3.85	3.46	3.15	2.88	2.65	2.45	2.28	2.13	2.01
PRICE SERIES	3.04	3.01	2.98	2.95	2.91	2.88	2.85	2.82	2.79	2.76	2.74
INVESTMENT	3.80	3.62	3.44	3.26	3.08	2.88	2.68	2.47	2.27	2.06	1.84
ANNUAL OPERATING COSTS	3.73	3.53	3.35	3.18	3.03	2.88	2.74	2.62	2.50	2.39	2.30

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-38

PUBLIC COMPANY

DEPTH: 1000'

SENSITIVITY IN NPV (15% DISCOUNT RATE)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*
IN $1000

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	140	206	272	338	404	469	535	601	667	733	799
PRICE SERIES	440	446	452	458	463	469	475	481	487	493	499
INVESTMENT	362	383	405	426	448	469	491	513	534	556	577
ANNUAL OPERATING COSTS	319	349	379	409	439	469	500	530	560	590	620

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-39

PUBLIC COMPANY

DEPTH: 2000'

SENSITIVITY IN NPV (15% DISCOUNT RATE)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*
IN $1000

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	110	176	242	308	374	440	506	572	637	703	769
PRICE SERIES	410	416	422	428	434	440	446	452	458	464	469
INVESTMENT	325	348	371	394	417	440	463	485	508	531	554
ANNUAL OPERATING COSTS	289	319	349	379	410	440	470	500	530	560	591

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

TABLE 3-40

PUBLIC COMPANY DEPTH: 3000'

SENSITIVITY IN NPV (15% DISCOUNT RATE)
TO CHANGES IN COMPONENTS OF CASH FLOW
FROM WORST TO BEST POSSIBLE SCENARIOS*
IN $1000

	0	.1	.2	.3	.4	.5	.6	.7	.8	.9	1.0
GAS PRODUCTION	81	147	212	278	344	410	476	542	608	674	740
PRICE SERIES	380	386	392	398	404	410	416	422	428	434	440
INVESTMENT	289	313	338	362	386	410	434	458	483	507	531
ANNUAL OPERATING COSTS	259	289	320	350	380	410	441	470	501	531	569

*When one of the four major components of cash flow is allowed to vary from worst to best possible scenarios, the other three major components are kept fixed at the midpoint between their worst and best situations. Hence, for each well depth and profitability measure, the mid-scenarios are the same.

throughout the next decade.) This was accomplished for fixed rates of 0% per annum (i.e., no change in price) to a 20% rate, in increments of 1%. Since it was assumed that production would commence in 1985, the forecasted range for 1985 gas prices was used and the low and high price forecasts for 1985 were taken as two starting points. Thus, the three profitability measures were calculated for each well depth for a private and a public company for both starting points. All other forecasted items were kept at their mid scenarios. These results are shown in Tables 3-41 to 3-46 and Figures 3-10 through 3-12.

The data show quite clearly how profitability increases with greater price increases. It is interesting that even with no net price increase (the 0% scenario), the proposed development scenario remains profitable.

A similar type of sensitivity analysis was completed for net gas output (Tables 3-47 and 3-48, Figures 3-13 and 3-14). The profitability measures were calculated (for the three depth scenarios and for private and public companies) for net gas outputs of 40 MCF/day to 200 MCF/day in increments of 20 MCF/day. A well is profitable (i.e., achieves a 15% IRR) for a private company if net production is about 70 MCF/day or more and for a public company, if net production is 60 MCF/day or more. Thus if the daily production rate of a well is in the range of 75 - 80 MCF, it is likely that the well will be profitable, even if well downtime somewhat exceeds 10%.

After the initial analysis was completed, supplemental updated data relating to the cost of developing and operating a typical 2000-foot methane well was obtained. This data is to be regarded as indicating a typical cost scenario in the Warrior Basin. This data gives rise to the following costs:

TABLE 3-41

PRIVATE COMPANY

SENSITIVITY IN IRR IN % TO GAS PRICES
WHICH ARE COMPOUNDED ANNUALLY

1985 Price*	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
										DEPTH:	1000'
$3.00/MCF	5.03	6.60	8.10	9.55	10.96	12.33	13.63	14.90	16.11	17.30	18.47
$3.50/MCF	11.70	13.15	14.51	15.79	17.03	18.24	19.44	20.60	21.75	22.87	23.99
$4.00/MCF	17.29	18.54	19.77	20.98	22.16	23.33	24.48	25.62	26.74	27.85	28.95
$4.50/MCF	22.03	23.24	24.44	25.61	26.77	27.92	29.05	30.17	31.28	32.38	33.47
$5.00/MCF	26.52	27.71	28.88	30.03	31.18	32.31	33.43	34.53	35.63	36.72	37.80
										DEPTH:	2000'
$3.00/MCF	3.07	4.58	6.04	7.45	8.82	10.14	11.44	12.69	13.89	15.07	16.21
$3.50/MCF	9.26	10.67	12.04	13.34	14.58	15.78	16.95	18.09	19.22	20.33	21.43
$4.00/MCF	14.73	15.95	17.15	18.32	19.48	20.62	21.75	22.85	23.95	25.03	26.11
$4.50/MCF	19.16	20.35	21.82	22.67	23.80	24.92	26.03	27.12	28.21	29.28	30.35
$5.00/MCF	23.31	24.47	25.62	26.75	27.87	28.97	30.07	31.15	32.23	33.30	34.36
										DEPTH:	3000'
$3.00/MCF	1.41	2.88	4.30	5.67	6.99	8.29	9.55	10.78	11.98	13.14	14.27
$3.50/MCF	7.22	8.59	9.92	11.22	12.47	13.67	14.83	15.97	17.07	18.16	19.23
$4.00/MCF	12.49	13.72	14.90	16.05	17.19	18.30	19.40	20.49	21.56	22.62	23.67
$4.50/MCF	16.77	17.93	19.08	20.20	21.31	22.41	23.49	24.56	25.63	26.69	27.72
$5.00/MCF	20.64	21.78	22.90	24.01	25.11	26.19	27.26	28.33	29.38	30.43	31.47

* The first year of production is assumed to be 1985.

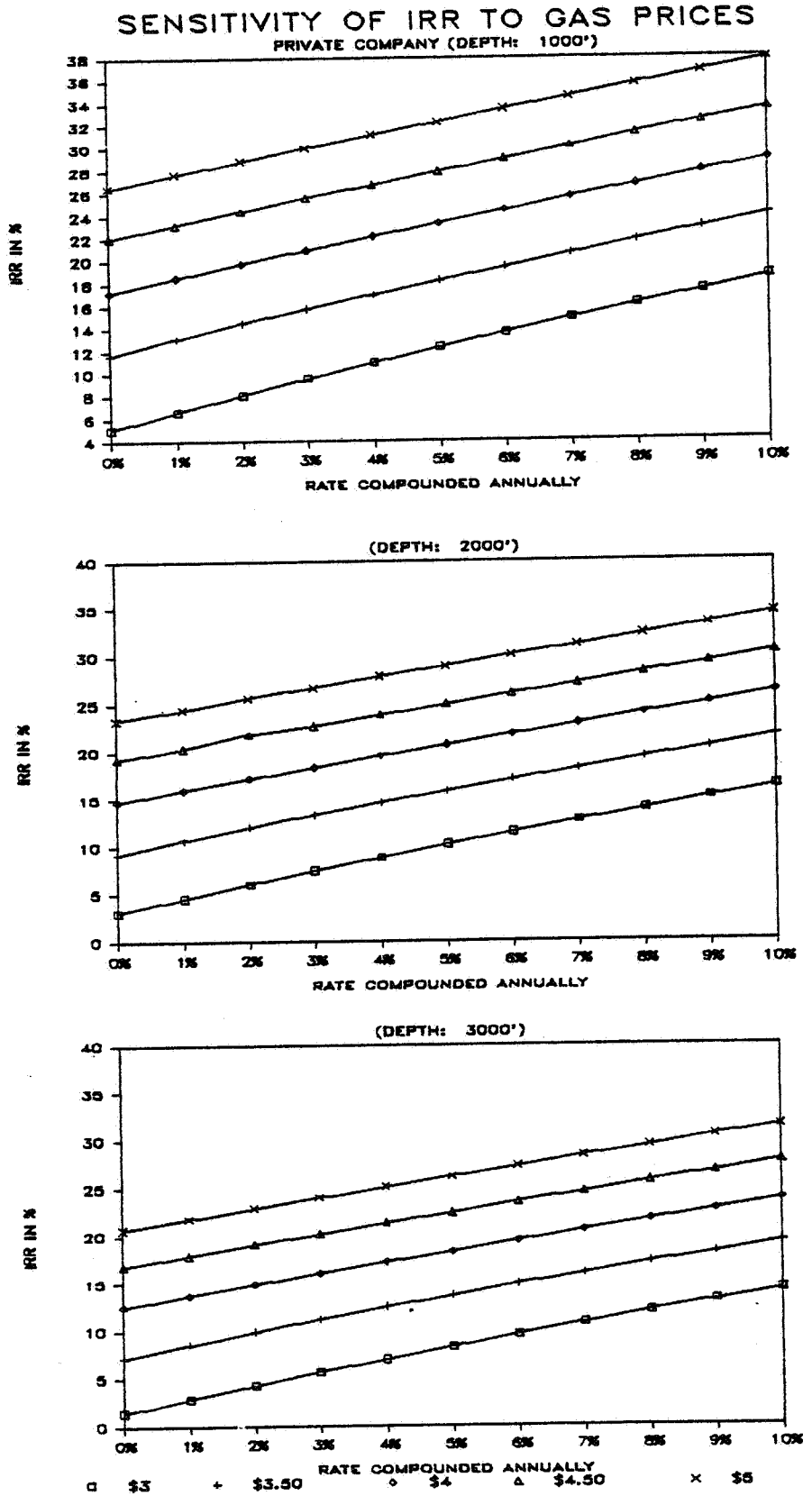

Figure 3-10 Graphical Representation of Sensitivity of IRR to Gas Prices, Private Company

TABLE 3-42

PRIVATE COMPANY

SENSITIVITY IN PAYBACK IN YEARS TO GAS PRICES
WHICH ARE COMPOUNDED ANNUALLY

1985 Price*	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
										DEPTH:	1000'
$3.00/MCF	7.76	7.72	6.79	6.43	6.12	5.85	5.63	5.43	5.27	5.13	5.00
$3.50/MCF	5.38	5.13	4.95	4.83	4.72	4.61	4.52	4.43	4.35	4.28	4.21
$4.00/MCF	4.33	4.24	4.16	4.08	4.01	3.95	3.88	3.82	3.76	3.71	3.66
$4.50/MCF	3.74	3.67	3.61	3.56	3.51	3.46	3.41	3.37	3.33	3.29	3.25
$5.00/MCF	3.28	3.24	3.20	3.16	3.12	3.08	3.05	3.02	2.99	2.96	2.93
										DEPTH:	2000'
$3.00/MCF	8.72	8.06	7.53	7.11	6.75	6.43	6.17	5.94	5.73	5.55	5.39
$3.50/MCF	6.10	5.79	5.52	5.30	5.13	4.98	4.87	4.77	4.68	4.59	4.51
$4.00/MCF	4.71	4.60	4.51	4.42	4.33	4.26	4.19	4.12	4.06	4.00	3.94
$4.50/MCF	4.07	4.00	3.93	3.87	3.80	3.75	3.69	3.64	3.59	3.54	3.50
$5.00/MCF	3.59	3.54	3.49	3.44	3.39	3.35	3.31	3.27	3.23	3.20	3.16
										DEPTH:	3000'
$3.00/MCF	9.44	8.89	8.27	7.77	7.35	7.00	6.68	6.41	6.18	5.99	5.79
$3.50/MCF	6.82	6.44	6.12	5.85	5.62	5.42	5.26	5.11	4.99	4.89	4.80
$4.00/MCF	5.12	4.96	4.84	4.74	4.65	4.56	4.48	4.40	4.33	4.26	4.20
$4.50/MCF	4.39	4.30	4.23	4.15	4.08	4.02	3.96	3.90	3.84	3.79	3.74
$5.00/MCF	3.88	3.82	3.76	3.71	3.65	3.60	3.55	3.51	3.46	3.42	3.38

* The first year of production is assumed to be 1985.

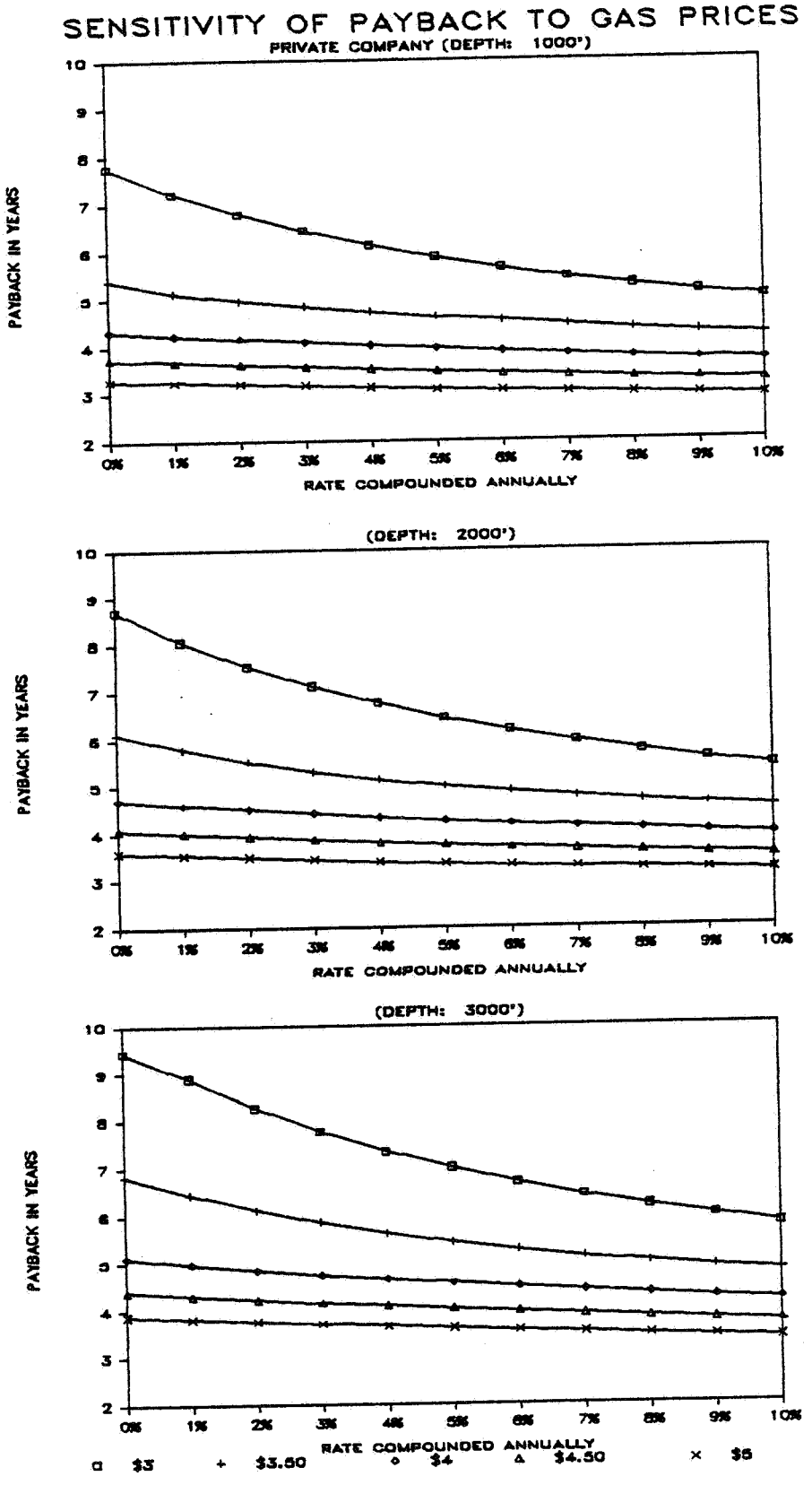

Figure 3-11 Graphical Representation of Sensitivity of Payback to Gas Prices, Private Company

TABLE 3-43

PRIVATE COMPANY

SENSITIVITY IN NPV IN $'000 TO GAS PRICES
WHICH ARE COMPOUNDED ANNUALLY
(15% DISCOUNT RATE)

1985 Price*	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
										DEPTH:	1000'
$3.00/MCF	(82)	(72)	(61)	(50)	(38)	(26)	(14)	(1)	12	26	40
$3.50/MCF	(28)	(17)	(5)	8	20	33	47	61	76	92	108
$4.00/MCF	20	33	46	59	73	88	104	120	137	155	173
$4.50/MCF	65	79	93	108	124	141	158	177	196	216	237
$5.00/MCF	109	125	141	158	175	194	213	234	255	277	300
										DEPTH:	2000'
$3.00/MCF	(108)	(98)	(87)	(76)	(64)	(52)	(40)	(27)	(13)	1	15
$3.50/MCF	(54)	(42)	(30)	(17)	(5)	9	22	37	52	68	84
$4.00/MCF	(3)	10	23	36	50	65	80	97	114	132	150
$4.50/MCF	42	56	71	86	102	118	136	154	173	193	214
$5.00/MCF	87	102	118	135	153	171	191	211	232	254	278
										DEPTH:	3000'
$3.00/MCF	(134)	(124)	(113)	(102)	(90)	(78)	(66)	(52)	(39)	(25)	(10)
$3.50/MCF	(80)	(68)	(56)	(43)	(30)	(16)	(2)	12	28	43	60
$4.00/MCF	(27)	(14)	(1)	12	27	41	57	73	90	108	127
$4.50/MCF	20	33	48	63	79	96	113	131	151	171	192
$5.00/MCF	64	79	95	112	130	149	168	188	209	232	255

* The first year of production is assumed to be 1985.

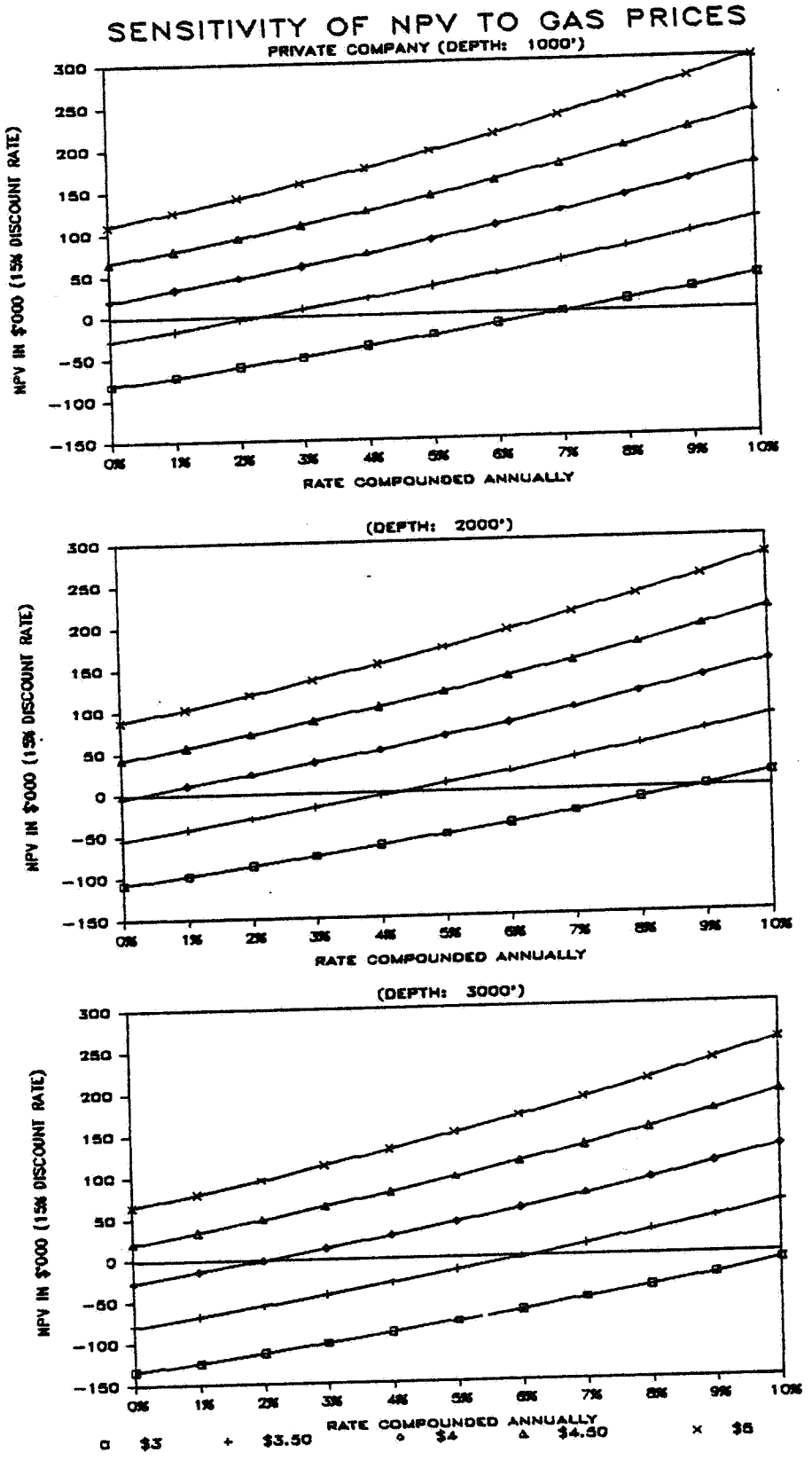

Figure 3-12 Graphical Representation of Sensitivity of NPV to Gas Prices, Private Company

TABLE 3-44

PUBLIC COMPANY

SENSITIVITY IN IRR IN % TO GAS PRICES
WHICH ARE COMPOUNDED ANNUALLY

1985 Price*	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
										DEPTH:	1000'
$3.00/MCF	8.75	10.80	12.72	14.54	16.28	17.95	19.55	21.10	22.61	24.08	25.51
$3.50/MCF	17.35	19.13	20.84	22.48	24.07	25.62	27.12	28.58	30.01	31.41	32.79
$4.00/MCF	25.06	26.69	28.27	29.81	31.31	32.78	34.21	35.62	37.00	38.35	39.69
$4.50/MCF	32.29	33.82	35.32	36.78	38.22	39.63	41.02	42.38	43.72	45.05	46.36
$5.00/MCF	39.21	40.68	42.12	43.53	44.92	46.29	47.64	48.97	50.29	51.59	52.87
										DEPTH:	2000'
$3.00/MCF	6.24	8.26	10.15	11.94	13.64	15.28	16.85	18.38	19.85	21.29	22.69
$3.50/MCF	14.27	16.03	17.71	19.33	20.90	22.41	23.89	25.32	26.73	28.10	29.45
$4.00/MCF	21.42	23.03	24.59	26.11	27.58	29.03	30.43	31.82	33.17	34.51	35.82
$4.50/MCF	28.06	29.58	31.06	32.51	33.92	35.31	36.68	38.02	39.34	40.64	41.93
$5.00/MCF	34.39	35.85	37.27	38.66	40.03	41.38	42.72	44.03	45.32	46.60	47.87
										DEPTH:	3000'
$3.00/MCF	4.10	6.10	7.96	9.73	11.40	13.01	14.56	16.06	17.51	18.92	20.30
$3.50/MCF	11.69	13.43	15.09	16.69	18.23	19.72	21.17	22.58	23.97	25.32	26.64
$4.00/MCF	18.39	19.98	21.52	23.02	24.47	25.89	27.28	28.64	29.98	31.29	32.58
$4.50/MCF	24.57	26.07	27.54	28.96	30.36	31.73	33.08	34.40	35.70	36.98	38.25
$5.00/MCF	30.43	31.87	33.27	34.65	36.01	37.34	38.65	39.95	41.23	42.49	43.74

* The first year of production is assumed to be 1985.

TABLE 3-45

PUBLIC COMPANY

SENSITIVITY IN PAYBACK IN YEARS TO GAS PRICES
WHICH ARE COMPOUNDED ANNUALLY

1985 Price*	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
										DEPTH:	1000'
$3.00/MCF	6.49	6.10	5.78	5.51	5.30	5.12	4.95	4.80	4.66	4.54	4.42
$3.50/MCF	4.60	4.44	4.30	4.18	4.07	3.98	3.88	3.80	3.72	3.65	3.58
$4.00/MCF	3.56	3.48	3.41	3.34	3.28	3.23	3.17	3.13	3.08	3.04	3.00
$4.50/MCF	2.91	2.86	2.82	2.78	2.74	2.71	2.67	2.64	2.61	2.58	2.55
$5.00/MCF	2.46	2.43	2.40	2.37	2.35	2.33	2.31	2.28	2.26	2.25	2.23
										DEPTH:	2000'
$3.00/MCF	7.28	6.79	6.40	6.08	5.82	5.59	5.39	5.22	5.07	4.93	4.79
$3.50/MCF	5.16	4.96	4.78	4.63	4.49	4.37	4.26	4.16	4.08	4.00	3.91
$4.00/MCF	4.00	3.90	3.80	3.71	3.64	3.56	3.50	3.43	3.38	3.32	3.28
$4.50/MCF	3.26	3.20	3.15	3.10	3.05	3.01	2.97	2.93	2.89	2.85	2.81
$5.00/MCF	2.76	2.72	2.68	2.65	2.62	2.59	2.56	2.53	2.50	2.48	2.45
										DEPTH:	3000'
$3.00/MCF	8.07	7.46	7.00	6.62	6.31	6.05	5.82	5.61	5.43	5.28	5.14
$3.50/MCF	5.72	5.47	5.25	5.07	4.91	4.76	4.62	4.51	4.40	4.30	4.21
$4.00/MCF	4.43	4.30	4.19	4.08	3.99	3.90	3.82	3.74	3.67	3.61	3.55
$4.50/MCF	3.62	3.54	3.47	3.40	3.34	3.29	3.24	3.19	3.15	3.11	3.07
$5.00/MCF	3.06	3.01	2.96	2.92	2.88	2.84	2.81	2.77	2.74	2.71	2.68

* The first year of production is assumed to be 1985.

TABLE 3-46

PUBLIC COMPANY

SENSITIVITY IN NPV IN $'000 TO GAS PRICES
WHICH ARE COMPOUNDED ANNUALLY
(15% DISCOUNT RATE)

1985 Price*	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
										DEPTH:	1000'
$3.00/MCF	(55)	(39)	(22)	(5)	14	33	53	74	97	120	144
$3.50/MCF	22	41	60	81	103	125	149	173	199	226	255
$4.00/MCF	99	121	143	167	191	217	244	272	302	333	365
$4.50/MCF	177	201	226	252	280	309	339	371	404	439	476
$5.00/MCF	254	281	309	338	369	401	435	470	507	546	586
										DEPTH:	2000'
$3.00/MCF	(85)	(69)	(52)	(34)	(16)	3	24	45	67	90	115
$3.50/MCF	(8)	11	31	51	73	95	119	144	170	197	225
$4.00/MCF	70	91	114	137	162	187	214	243	272	303	336
$4.50/MCF	147	171	196	223	250	279	310	341	375	410	446
$5.00/MCF	224	251	279	308	339	371	405	440	477	516	557
										DEPTH:	3000'
$3.00/MCF	(114)	(98)	(82)	(69)	(46)	(26)	(6)	15	37	61	85
$3.50/MCF	(37)	(18)	1	22	43	66	89	114	140	167	195
$4.00/MCF	40	61	84	107	132	158	185	213	243	274	306
$4.50/MCF	117	141	167	193	221	250	280	312	345	380	416
$5.00/MCF	195	221	249	279	309	342	375	411	448	486	527

* The first year of production is assumed to be 1985.

TABLE 3-47

SENSITIVITY OF PROFITABILITY MEASURES TO CHANGES IN NET GAS OUTPUT*

PRIVATE COMPANY

		NET GAS OUTPUT, MCF/DAY								
	DEPTH	40	60	80	100	120	140	160	180	200
IRR in %	1000'	-4.63	10.43	20.98	29.39	36.89	43.98	50.81	57.45	63.98
	2000'	-5.89	8.44	18.49	26.45	33.39	39.91	46.16	52.22	58.14
	3000'	-6.98	6.71	16.36	23.94	30.46	36.53	42.31	47.90	53.35
PAYBACK IN YEARS	1000'	-	6.61	4.44	3.50	2.90	2.46	2.15	1.90	1.71
	2000'	-	7.15	4.76	3.77	3.15	2.69	2.35	2.09	1.88
	3000'	-	7.66	5.09	4.03	3.37	2.91	2.54	2.26	2.04
NPV in $'000 (15% DISCOUNT RATE)	1000'	(181)	(47)	67	170	271	372	473	574	675
	2000'	(211)	(74)	42	147	248	349	450	551	652
	3000'	(240)	(101)	18	124	226	327	428	529	630

*All other components at their mid scenarios

TABLE 3-48

SENSITIVITY OF PROFITABILITY MEASURES TO CHANGES IN NET GAS OUTPUT*

PUBLIC COMPANY

		NET GAS OUTPUT, MCF/DAY								
	DEPTH	40	60	80	100	120	140	160	180	200
IRR in %	1000'	-1.81	15.69	29.02	40.92	52.18	63.13	73.91	84.61	95.28
	2000'	-3.27	13.35	25.80	36.78	47.06	56.98	66.71	76.33	85.89
	3000'	-4.55	11.34	23.09	33.32	42.83	51.95	60.84	69.60	78.28
PAYBACK IN YEARS	1000'	-	5.80	3.83	2.80	2.19	1.79	1.51	1.31	1.16
	2000'	-	6.24	4.17	3.09	2.42	1.99	1.68	1.46	1.29
	3000'	-	6.64	4.50	3.35	2.65	2.18	1.85	1.60	1.42
NPV in $'000 (15% DISCOUNT RATE)	1000'	(167)	8	184	360	535	711	887	1062	1238
	2000'	(197)	(21)	154	330	506	681	857	1033	1208
	3000'	(227)	(51)	125	300	476	652	827	1003	1179

*All other components at their mid scenarios

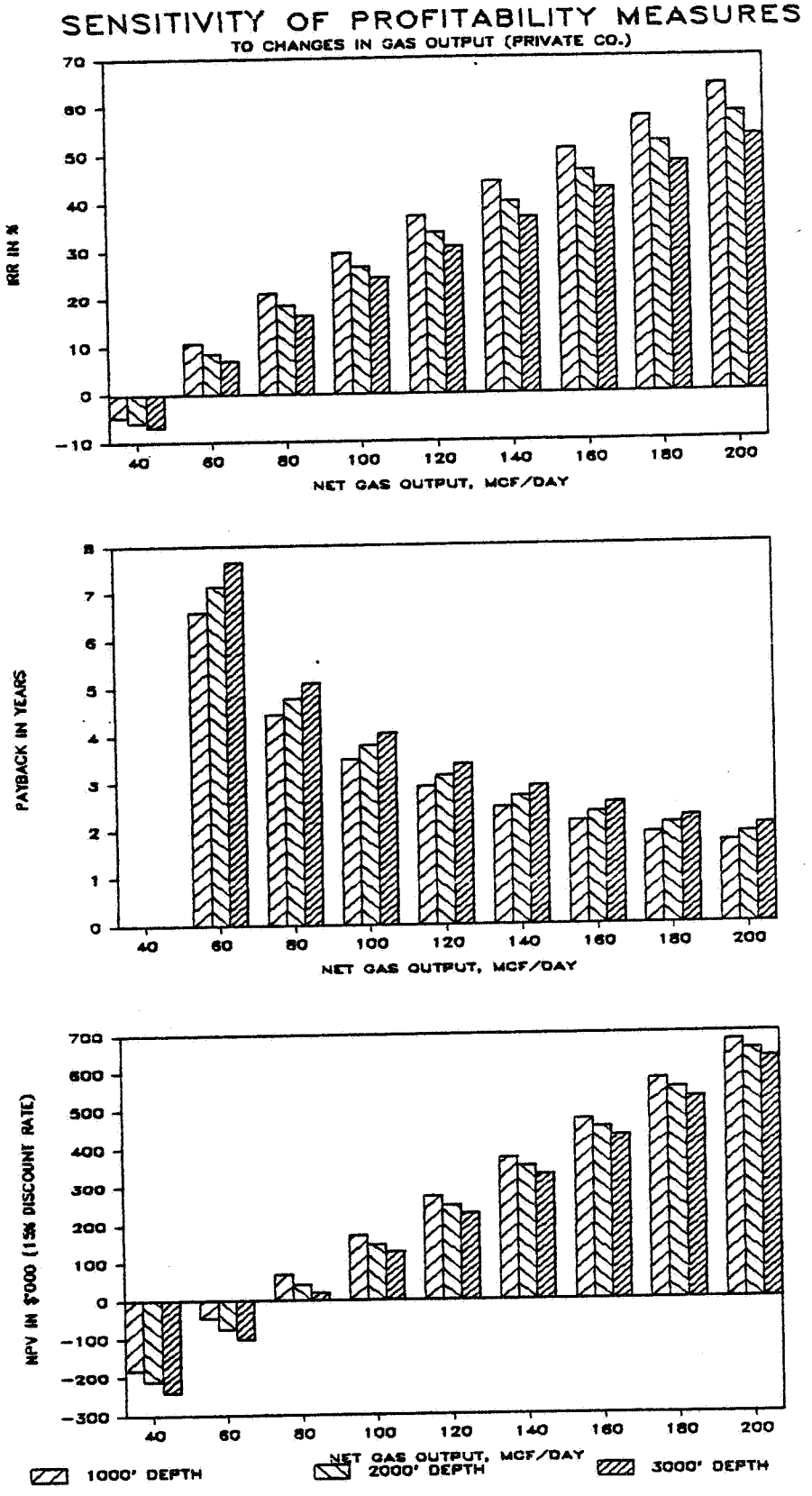

Figure 3-13 Graphical Representation of Sensitivity of Profitability Measures to Changes in Gas Output, Private Company

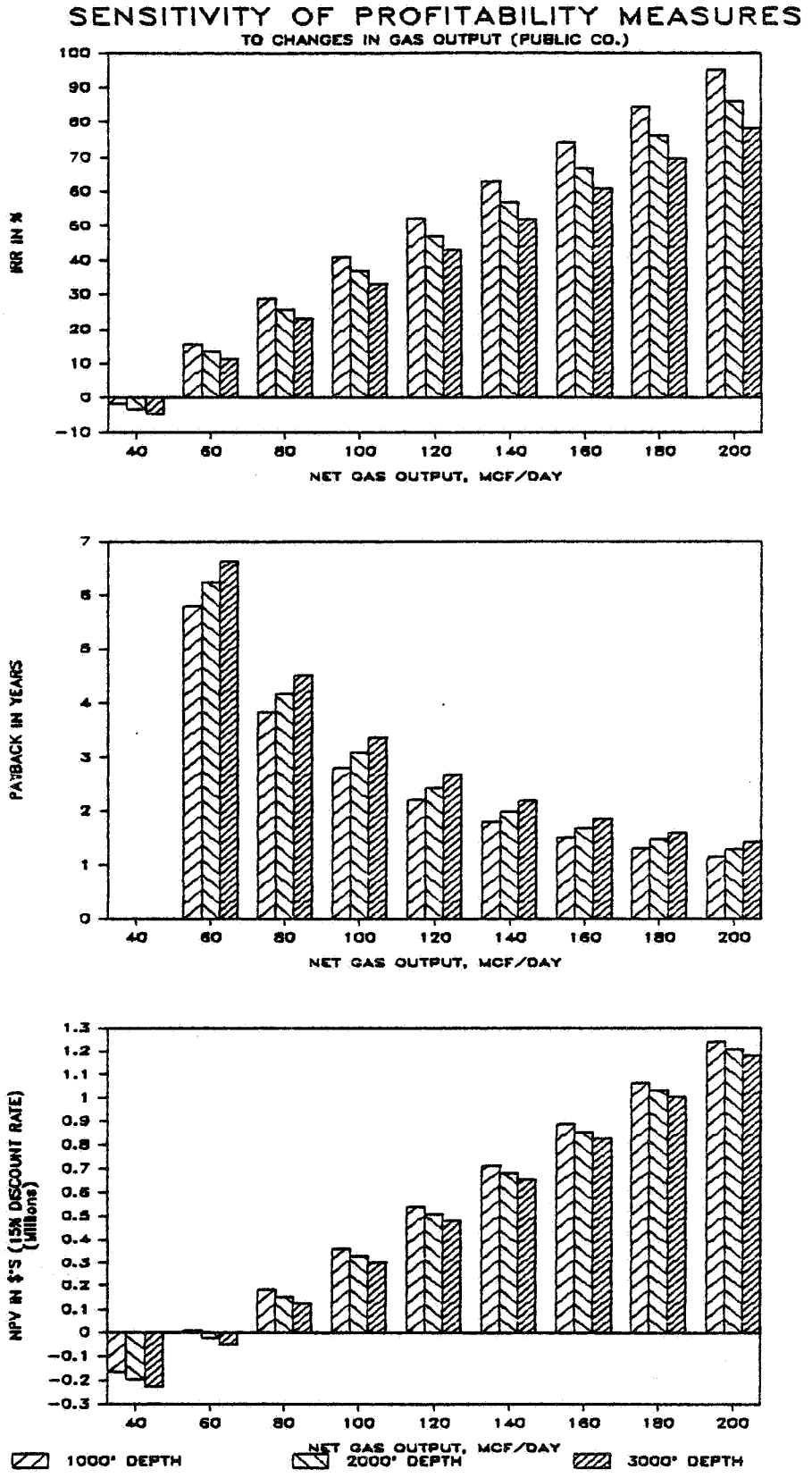

Figure 3-14 Graphical Representation of Sensitivity of Profitability Measures to Changes in Gas Output, Public Company

Tangible cost	$103,000
Intangible cost	$122,500
Operating cost	$ 45,000

Even with this data, the uncertainties regarding gas output and gas prices remain. Both these items are explained above. A worst/best or low/high bracketing was implemented for these two items, instead of the incremental scenarios used previously. The profitability measures for this were provided in Table 3-1. These projections indicate that the forecasted range for gas output gives rise to the largest variation in profitability. In this study, the worst possible situation, low gas output and low gas prices, is profitable for both a private and a public company within the constraints of the costs, production, and prices assumed.

RELATIONSHIP OF RESOURCE BASE TO PROFITABILITY

One important aspect of any economic feasibility study involving natural resources is the relationship of the quantity of projected in-place resources to the profitability of exploitation. This is true in the case of general studies (such as here presented) and in site-specific studies as well.

Clearly, the net gas output for sales and the price at the wellhead determine gross revenue. Reservoir characteristics, including the specific gas content and thickness of producing zones, permeability, water content, and other factors, such the development of additional wells in a field, determine the gas flow rate.

The impact of changes in flow rate on profitability has been clearly shown for a private company in Figure 3-13 and a public company in Figure 3-14 (see Tables 3-21 and 3-22). These data assume all other components (price and costs) are at their middle values.

For the purposes of this discussion, it is assumed that a minimum 15% IRR and a maximum payback of 5 years are the indicators by which profitability is judged. Potential developers will have their own guidelines, but those chosen are believed to be representative.

Using the above criteria, minimum net daily flows were derived which yield an IRR of at least 15% for both public and private developers and for an expected price of $4.75/MCF to $3.75/MCF. These derivations (Tables 3-49 and 3-50) show that the minimum flows range from about 59 MCF/day for public company, 1000 foot well at $4.75/MCF in 1985 to 98 MCF/day for a private company well at 3000 feet and $3.75/MCF.

TABLE 3-49

MINIMUM NET/GROSS DAILY GAS OUTPUT (MCF)
REQUIRED FOR PROFITABILITY @ $4.75/MCF*

Depth	Private	Public
1000'	69/76	59/65
2000'	73/80	63/69
3000'	77/85	66/73

TABLE 3-50

MINIMUM NET/GROSS DAILY GAS OUTPUT (MCF)
REQUIRED FOR PROFITABILITY @ $3.75/MCF*

Depth	Private	Public
1000'	88/97	75/83
2000'	93/102	80/88
3000'	98/108	84/92

*Assumes a 10-year well life and a conservative uniform production rate. Profitability is based on (1) a 15% IRR and payback of 5 years, and (2) costs are fixed at their mid scenario values (p. 3-21).

The above minimum daily flows were then used to project requirements for recoverable methane based on a 10-year well life and a flat production scenario. The results (Tables 3-51 and 3-52 ranged from 215 MMCF/40 acres to 358 MMCF/40 acres. Recoverable methane in the Warrior Coal Basin is generally assumed to range from 50 to 80% of the total methane in the completed zones.

A quick reference graphical guide to economic feasibility under the conditions previously described was constructed. The graphs show a range of possible combinations of coal thickness and specific gas content which yield a potentially profitable resource base for 1985 wellhead prices of $3.75 and $4.75/MCF (Figures 3-15 and 3-16). A comparison of public vs. private company profitability is also provided (Figures 3-17 and 3-18). For the purposes of this analysis, producible coal is limited to coal zones in which coal thickness equals or exceeds 2 feet in a 10-foot interval.

These graphs are intended to illustrate a point and should be supplemented with other data during the decision-making process even when actual conditions are similar to the basic assumptions used.

It seems appropriate to underscore that many variations on the theme are possible depending on the nature and requirements of specific developers. Some examples follow:

- The most common situation will probably be a public company developing on leased land, but significant development by private concerns is possible, particularly if the company holds fee simple title to large tracts. In the Warrior Basin, a healthy forest products industry has resulted in significant large tracts being owned in fee by privately-held and public companies.
- Any developer that owns land in fee will not be concerned with royalty payments nor compensation for surface damages.

TABLE 3-51

MINIMUM RECOVERABLE RESOURCES
NECESSARY FOR PROFITABILITY AT A
1985 GAS PRICE OF $4.75/MCF
(MMCF/40 Acres)*

Depth	Private	Public
1000'	252	215
2000'	266	230
3000'	281	241

TABLE 3-52

MINIMUM RECOVERABLE RESOURCES
NECESSARY FOR PROFITABILITY AT A
1985 GAS PRICE OF $3.75/MCF
(MMCF/40 Acres)*

Depth	Private	Public
1000'	321	274
2000'	339	292
3000'	358	307

*Assumes a 10-year well life and a conservative uniform production rate. Profitability is based on (1) a 15% IRR and payback of 5 years, and (2) costs are fixed at their mid scenario values (p. 3-21).

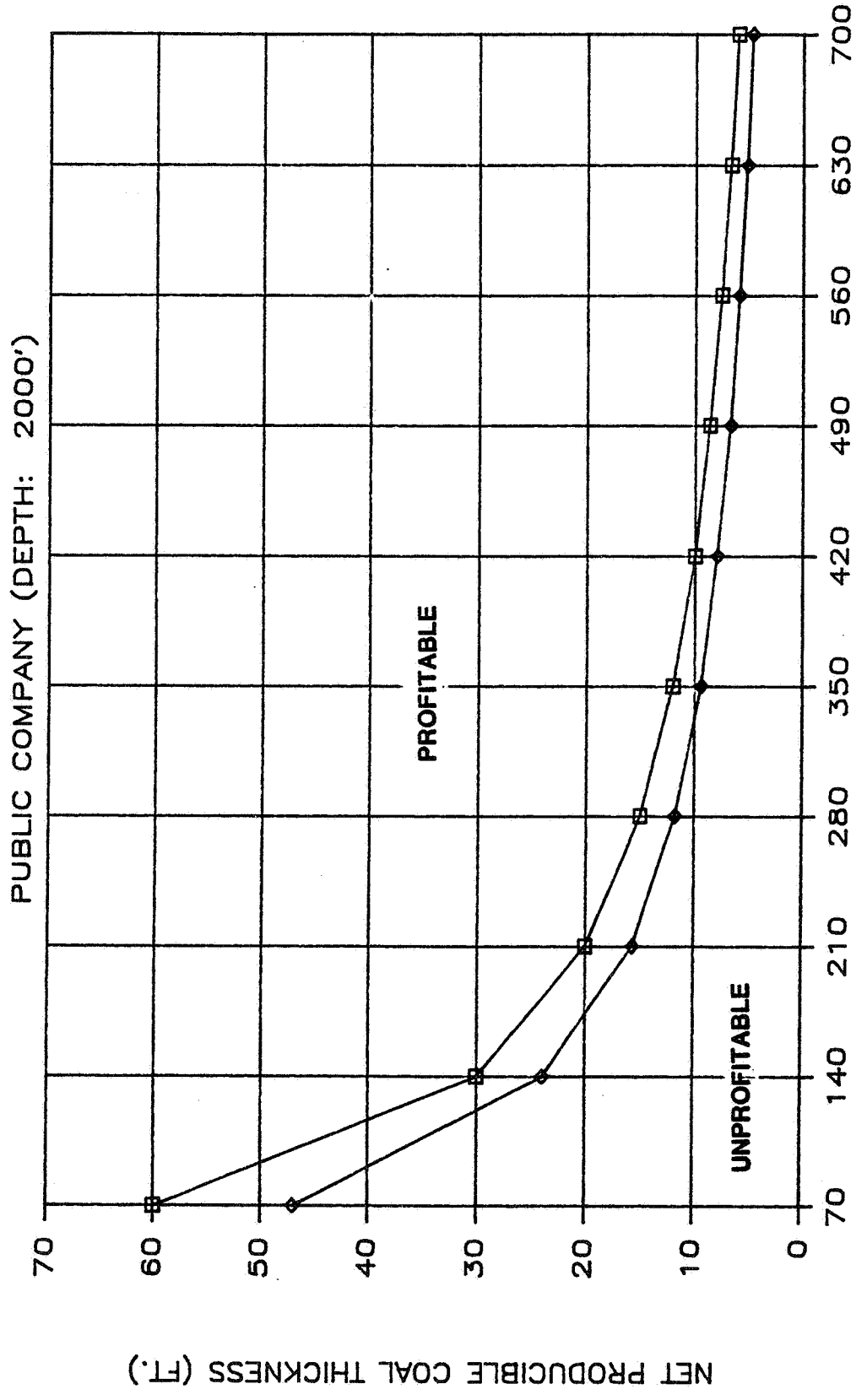

Figure 3-15. Relationship of Profitability to Resource Base (Gas Content, Coal Thickness), Gas Price, and Well Cost at 2000 feet for a Public Company.

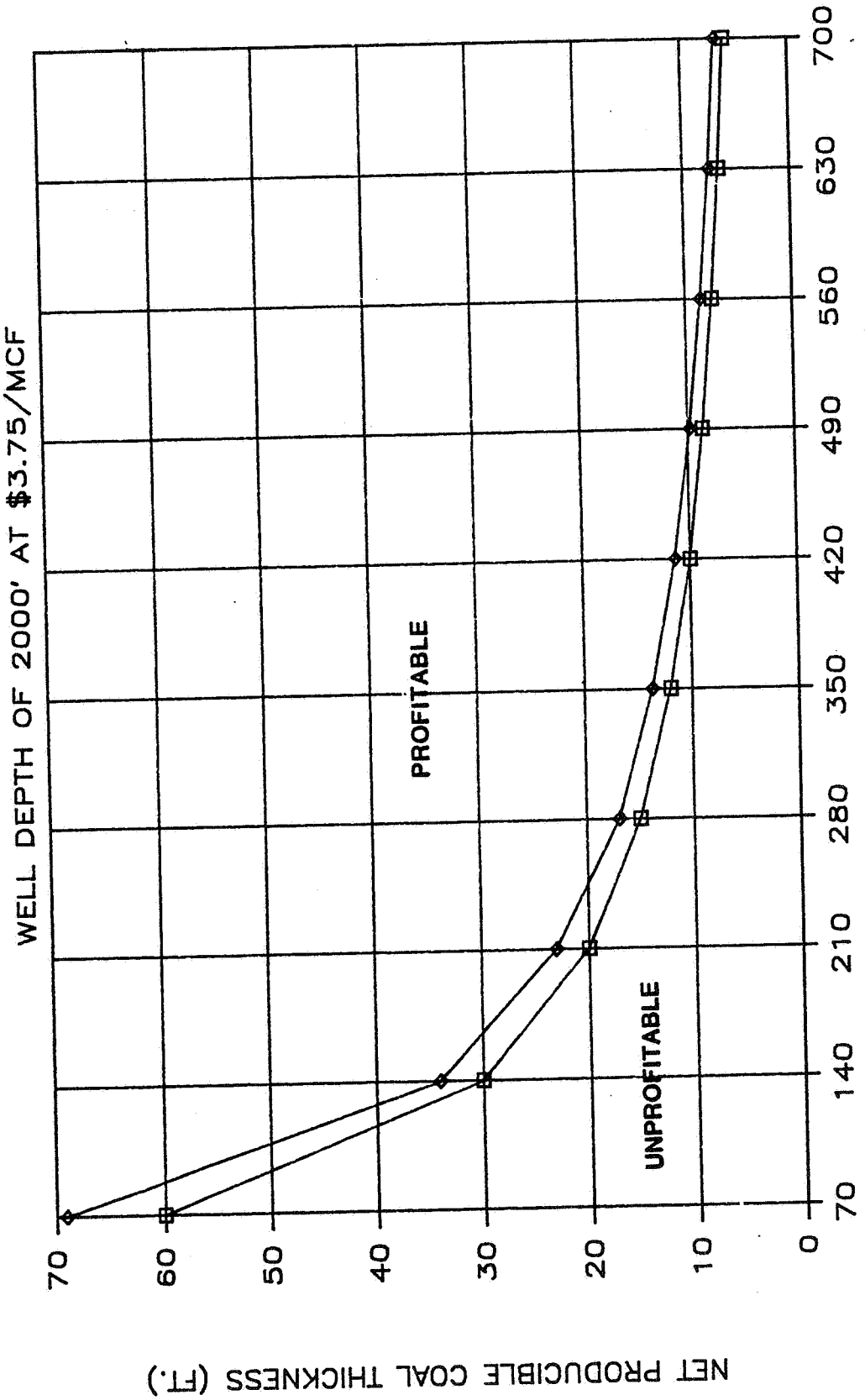

Figure 3-16. Comparison of Relationship of Resource Base to Profitability at $3.75/MCF for Private vs Public Company.

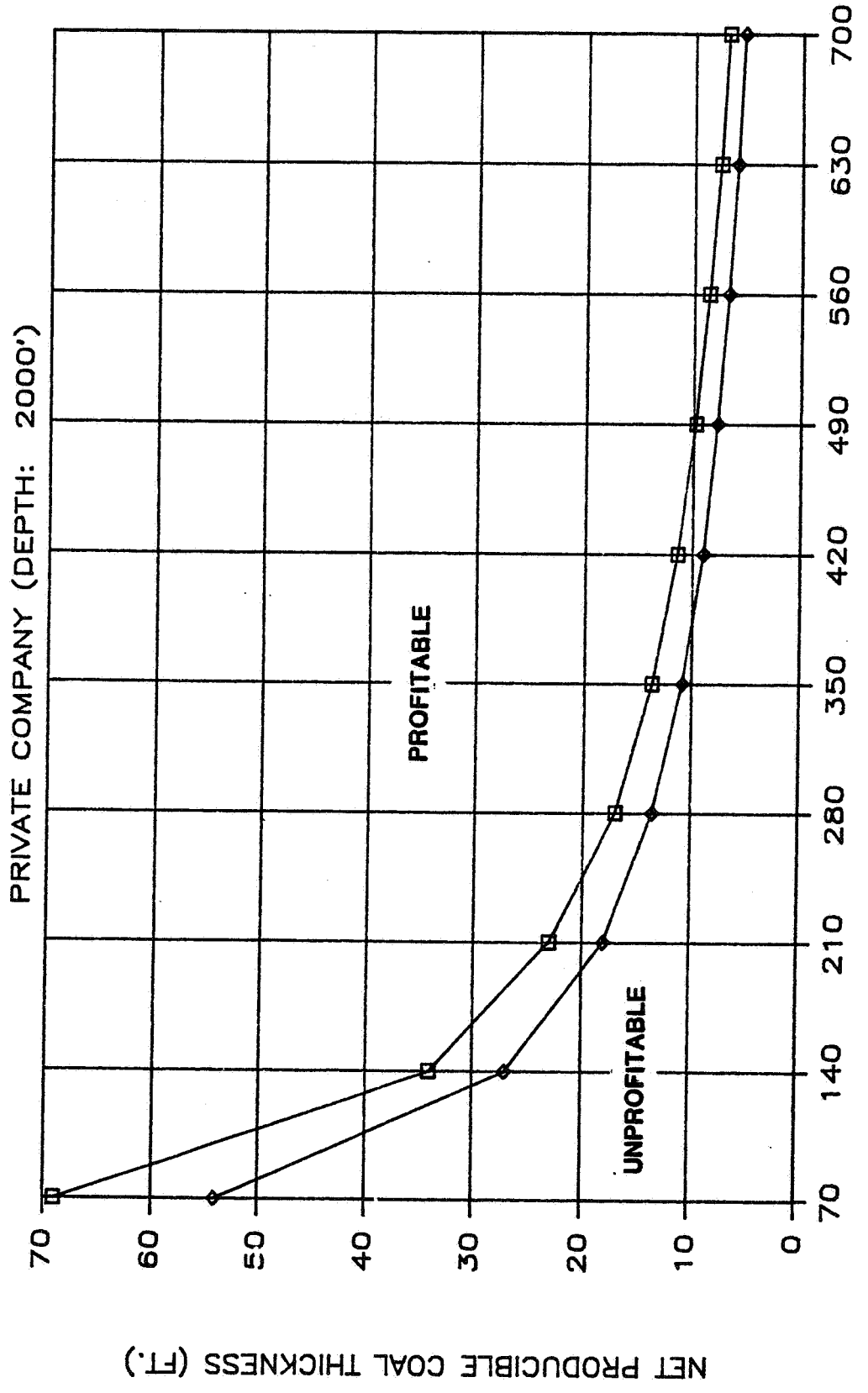

Figure 3-17. Relationship of Profitability to Resource Base (Gas Content, Coal Thickness), Gas Price, and Well Cost at 2000 feet for a Private Company.

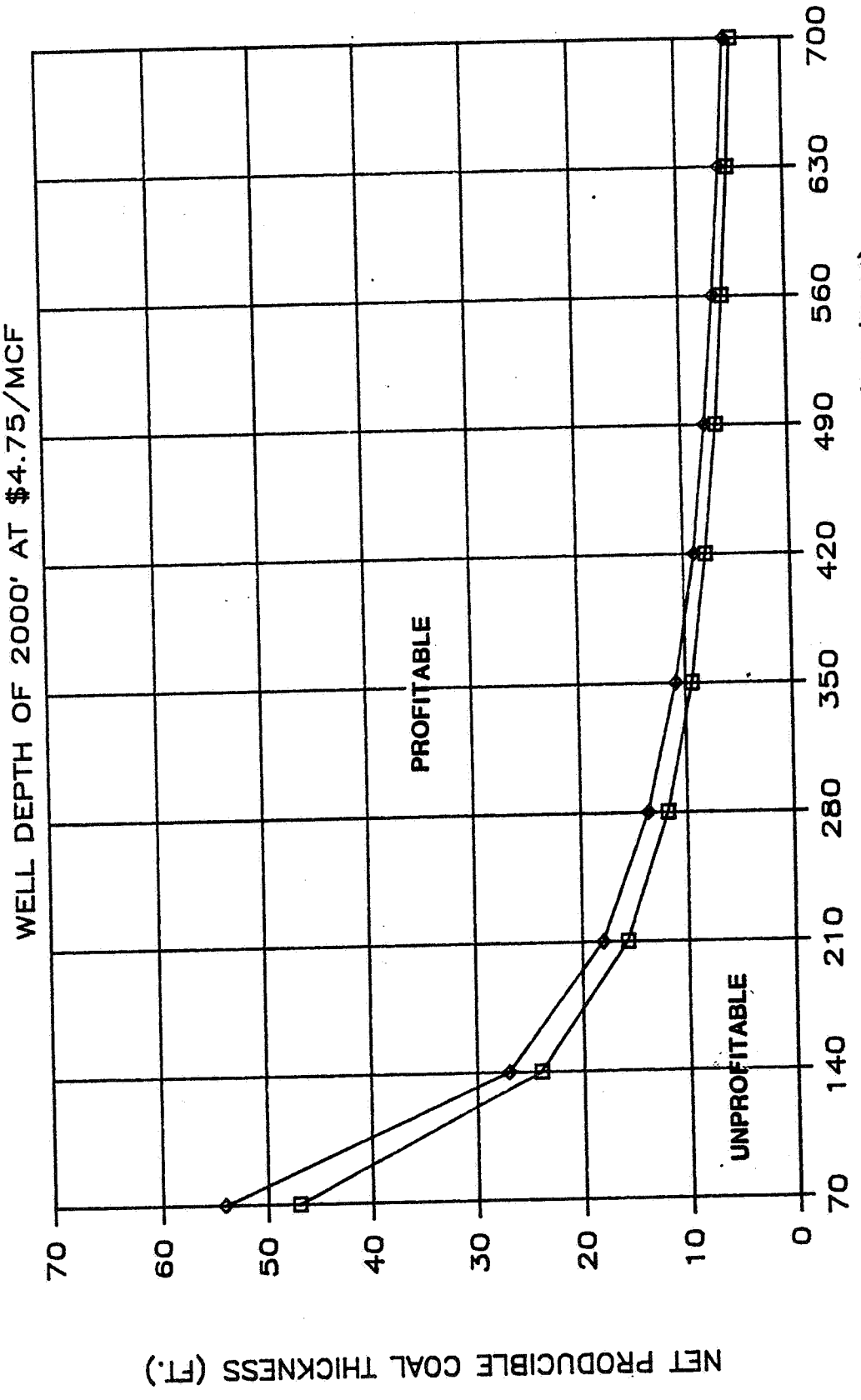

Figure 3-18. Comparison of Relationship of Resource Base to Profitability at $4.75/MCF for Private vs Public Company.

- If a public industrial corporation that is a large user of gas develops coalbed methane on its own fee simple lands, no royalty need be subtracted from gross revenues and profitability will in part be determined by what it pays for gas from its supplier, not by the wellhead price.

Finally, it is emphasized that economic parameters are dynamic. Improvements in technology, the relationship of gas supply to demand, changes in intrest rates and inflation rates, geopolitical energy problems, changing legal perspectives, and government policy all significantly impact economic feasibility at any point in time. It is necessary to frequently update economic studies to account for such changes. A synopsis of a typical gas property development scenario (shown in Table 3-53) illustrates the importance of updating economic evaluations as development proceeds from its beginnings in regional exploration through full field development.

TABLE 3-53

GAS PROPERTY DEVELOPMENT PATH

Regional Exploration	Prospect Generation	Prospect Evaluation	Confirmation Drilling	Field Development
Determine Magnitude and Distribution of Coalbed Gas	Conduct Geologic and Hydrology Analyses to Determine:	Test Via "Proof" or "Wild Cat" Wells	Design Production System	Drill and Complete Wells
	• Thickness		• Well Siting	
Determine Reserves in Context of Gas Market	• Gas Content and Depth of Coal	Determine Well Spacing	• Gathering System	Stimulate as Required
			• Drilling Schedule	
Select Properties for Prospect Generation Evaluation	Estimate Costs of Developing Property	Predict Production	Estimate Costs	Work Over Wells as Required
		Conduct/Update Economic Projections	Drill, Complete Wells	Update Production Estimates
	Conduct Economic Analyses		Determine O&M Requirements	Monitor and Update Economic Viability
	Obtain a Lease Position	Negotiate Sales Contract	Update Economic Assessment	