ALASKA LEGISLATURE COMMITTEE FILES 1987-1988 8672
4944 HRES HB 164 (FILE 1) - HB 164 (FILE 2) (see ELF) 5/6

TABLE 2a
Calculation of State Petroleum Revenues as a
Percent of Adjusted Production Income
6/85 Forecast Assumptions 70% Case FY 85-05 Using WHV

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3525.22	31.42%
				Pre SB 524	
				Impact SB 524	
82	12958.93	1740.58	11218.35	3525.22	31.42%
83	11941.70	2113.21	9828.49	3270.36	33.27%
84	11327.62	2511.29	8816.33	3148.49	35.71%
85	11382.33	2832.59	8549.74	3161.10	36.97%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	11382.33	2832.59	8549.74	3297.36	38.57%
86	10626.57	3018.24	7608.33	3277.37	43.08%
87	10097.40	3372.15	6725.24	3008.16	44.73%
88	10290.63	3724.11	6566.52	2737.62	41.69%
89	10851.82	4006.66	6845.16	2811.92	41.08%
90	11219.23	4192.75	7026.48	2890.57	41.14%
91	11135.31	4239.84	6895.47	2845.35	41.26%
92	11619.35	4306.37	7312.98	2937.53	40.17%
93	11906.75	4294.64	7612.10	2999.89	39.41%
94	11555.98	4200.03	7355.96	2696.65	39.38%
95	11412.40	4134.28	7278.12	2839.38	39.01%
96	11031.65	4068.39	6963.25	2715.29	38.99%
97	10742.51	3988.64	6753.87	2606.74	38.60%
98	10330.41	3814.79	6515.62	2478.06	38.03%
99	9886.53	3668.77	6217.76	2343.22	37.69%
2000	9386.09	3490.23	5895.86	2196.96	37.26%
01	8490.22	3343.89	5146.33	1936.40	37.63%
02	7572.23	3202.43	4369.80	1665.97	38.12%
03	6788.11	3173.14	3614.98	1430.85	39.58%
04	5928.08	3088.80	2839.28	1190.54	41.93%
05	5324.82	3045.12	2279.70	1009.80	44.30%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3502.40	31.22%
				AS43.20 & 55	
82	12958.93	1740.58	11218.35	3928.80	35.02%
83	11941.70	2113.21	9828.49	3321.58	33.80%
84	11327.62	2511.29	8816.33	3220.43	36.53%
85	11382.33	2832.59	8549.74	3154.10	36.89%
				AS43.20 & 55	
85	11382.33	2832.59	8549.74	3154.10	36.89%
86	10626.57	3018.24	7608.33	3043.65	40.00%
87	10097.40	3372.15	6725.24	2969.30	44.15%
88	10290.63	3724.11	6566.52	2794.18	42.55%
89	10851.82	4006.66	6845.16	2856.64	41.73%
90	11219.23	4192.75	7026.48	2921.76	41.58%
91	11135.31	4239.84	6895.47	2858.94	41.46%
92	11619.35	4306.37	7312.98	2929.87	40.06%
93	11906.75	4294.64	7612.10	2974.17	39.07%
94	11555.98	4200.03	7355.96	2853.84	38.80%
95	11412.40	4134.28	7278.12	2793.96	38.39%
96	11031.65	4068.39	6963.25	2775.67	39.86%
97	10742.51	3988.64	6753.87	2548.60	37.74%
98	10330.41	3814.79	6515.62	2405.06	36.91%
99	9886.53	3668.77	6217.76	2257.66	36.31%
2000	9386.09	3490.23	5895.86	2103.35	35.68%
01	8490.22	3343.89	5146.33	1652.20	35.99%
02	7572.23	3202.43	4369.80	1602.40	36.67%
03	6788.11	3173.14	3614.98	1390.72	38.47%
04	5928.08	3088.80	2839.28	1182.56	41.65%
05	5324.82	3045.12	2279.70	1027.10	45.05%

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1) FY 1985 HB353 Corp. Inc. Tax includes $60.8m of AS43.20 already collected through December 31, 1984 and half a year of the new tax.

2) Based on 6/85 70% case price and production assumptions.

TABLE 2b
Calculation of State Petroleum Revenues as a
and as a Percent of Prod'n & Pipeline Income
6/85 Forecast Assumptions 70% Case FY 85-05 Using WHV

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3896.85	28.62%
				Pre SB 524	
				Impact SB 524	
82	16455.80	2839.52	13616.28	3896.85	28.62%
83	15469.75	3156.70	12313.06	3644.37	29.60%
84	14955.03	3492.67	11462.37	3544.02	30.92%
85	15135.98	3750.89	11385.10	3569.86	31.36%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	15135.98	3750.89	11385.10	3585.00	31.49%
86	14387.36	3907.71	10479.66	3687.41	35.19%
87	13930.61	4255.05	9675.56	3418.97	35.34%
88	14021.78	4590.92	9430.87	3138.59	33.28%
89	14534.91	4861.97	9672.95	3202.64	33.11%
90	14762.89	5041.00	9721.89	3265.45	33.59%
91	14396.60	5079.20	9317.41	3192.20	34.26%
92	14737.37	5132.85	9604.52	3263.10	33.97%
93	14836.00	5106.76	9729.24	3304.47	33.96%
94	14159.38	4997.89	9161.50	3169.51	34.60%
95	13768.29	4922.30	8846.00	3082.52	34.85%
96	13116.52	4847.39	8269.13	2928.73	35.42%
97	12584.20	4758.72	7825.49	2791.86	35.68%
98	11935.47	4573.61	7361.86	2636.14	35.81%
99	11277.87	4418.18	6859.69	2475.96	36.09%
2000	10584.46	4230.95	6353.52	2306.26	36.30%
01	9464.018	4078.47	5385.55	2020.33	37.51%
02	8342.030	3937.21	4404.82	1724.72	39.16%
03	7399.393	3914.46	3484.94	1467.52	42.11%
04	6391.219	3837.70	2553.52	1206.71	47.26%
05	5683.562	3806.07	1877.49	1008.45	53.71%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3664.40	26.91%
				AS43.20 & 55	
82	16455.80	2839.52	13616.28	4090.80	30.04%
83	15469.75	3156.70	12313.06	3478.98	28.25%
84	14955.04	3492.67	11462.37	3386.43	29.54%
85	15135.99	3750.89	11385.10	3316.10	29.13%
				AS43.20 & 55	
85	15135.98	3750.89	11385.10	3316.10	29.13%
86	14387.36	3907.71	10479.66	3199.42	30.53%
87	13930.61	4255.05	9675.56	3118.84	32.23%
88	14021.78	4590.92	9430.87	2937.49	31.15%
89	14534.91	4861.97	9672.95	2993.72	30.95%
90	14762.89	5041.00	9721.89	3052.61	31.40%
91	14396.60	5079.20	9317.41	2983.56	32.02%
92	14737.37	5132.85	9604.52	3048.25	31.74%
93	14836.00	5106.76	9729.24	3086.32	31.72%
94	14159.38	4997.89	9161.50	2959.76	32.31%
95	13768.29	4922.30	8846.00	2893.65	32.71%
96	13116.52	4847.39	8269.13	2859.13	34.70%
97	12584.20	4758.72	7825.49	2635.83	33.68%
98	11935.47	4573.61	7361.86	2486.06	33.77%
99	11277.87	4418.18	6859.69	2332.43	34.00%
2000	10584.46	4230.95	6353.52	2171.89	34.18%
01	9464.018	4078.47	5385.55	1914.51	35.55%
02	8342.030	3937.21	4404.82	1658.48	37.65%
03	7399.393	3914.46	3484.94	1440.57	41.34%
04	6391.219	3837.70	2553.52	1226.18	48.02%
05	5683.562	3806.07	1877.49	1064.48	56.70%

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1) FY 1985 HB353 Corp. Inc Tax includes $60.8m of AS43.20 already collected through December 1, 1984 and half a year of the new tax.

2) Based on 6/85 70% case price and production assumpuions.

TABLE 3
Pipeline, Production & Exploration
Income Tax Estimates
(mil current FY $)

Fiscal Year	Total Revenue	State Royalty Share	Prod'n Cons Tax	Total Property Tax	Total Oper'g Costs	Total Depre	Total Acquis Costs	Windfall Profits Tax	Interest Expense Uncap	Exploratn Costs	Admin Costs	Other Deductns	Total Deductns	Total Net Income	Liability HB 353 1)	Collections HB 353 1)	Collections AS 43.20 2)	Diff
82	15455.80	1564.30	1219.03	275.90	939.80	602.58	0.77	2017.66	720.69	190.90	236.20	148.58	7916.41	8539.40	802.70	837.62	130.72	706.90
83	15469.75	1442.73	1098.94	306.55	1100.56	780.16	0.98	1018.38	676.04	204.26	252.30	142.39	7023.30	8446.46	793.97	796.15	236.00	560.15
84	14955.04	1370.57	1032.93	357.66	1259.34	998.45	1.09	412.33	614.13	218.56	264.90	136.20	6666.16	8288.87	779.15	782.86	265.10	517.76
85	15135.99	1362.44	1013.86	396.56	1449.17	1093.32	0.80	70.26	565.55	233.86	278.20	130.00	6594.01	8541.97	802.95	797.00	168.60	628.40
85	15135.99	1362.44	1377.52	396.56	1449.17	1093.32	0.80	69.59	565.55	233.86	278.20	130.00	6887.41	8248.58	775.37	581.52	168.60	412.92
86	14387.37	1281.15	1262.27	420.27	1477.66	1224.05	0.76	46.77	541.76	247.56	292.10	123.82	6871.40	7515.97	706.50	723.72	235.73	487.99
87	13930.62	1212.62	1076.73	465.05	1600.34	1442.16	8.29	29.02	517.87	262.07	306.70	117.63	7009.45	6921.16	650.59	664.57	260.61	403.96
88	14021.79	1178.25	785.41	522.69	1735.17	1619.02	32.60	20.35	490.28	277.42	322.00	114.43	7077.27	6944.52	652.78	652.24	286.69	365.54
89	14534.92	1214.68	778.54	543.09	1796.67	[illegible].55	71.31	17.39	466.41	293.68	338.10	105.24	7398.28	7136.64	670.84	666.33	305.76	360.57
90	14762.89	1259.40	784.53	551.39	1854.43	[illegible].31	117.68	16.27	442.64	310.89	355.00	99.05	7636.32	7126.57	669.90	670.13	314.61	355.52
91	14396.61	1251.54	749.98	545.92	1855.24	1859.87	150.78	14.42	418.55	329.10	372.80	92.86	7626.64	6769.97	636.38	644.76	313.14	331.61
92	14737.37	1305.68	768.16	536.92	1880.35	1880.23	152.28	9.36	393.54	348.38	391.40	86.67	7743.81	6993.56	657.39	652.14	311.00	341.14
93	14836.01	1343.04	772.90	524.41	1801.28	1846.17	151.20	3.87	367.83	368.60	411.00	80.48	7747.11	7088.89	666.36	664.12	306.83	357.28
94	14159.38	1307.55	718.76	509.50	1846.56	1764.64	145.28	0.14	345.21	390.40	431.50	74.29	7533.70	6625.69	622.81	633.70	298.04	335.66
95	13768.30	1294.13	691.55	492.18	1794.52	1721.36	142.96	0.00	328.97	413.28	453.10	68.10	7400.16	6368.14	598.61	604.66	287.54	317.12
96	13116.53	1255.86	636.25	470.56	1762.00	1665.21	128.63	0.00	316.45	437.49	475.70	61.91	7210.06	5906.46	555.21	566.06	298.04	268.02
97	12564.21	1226.77	588.58	445.39	1736.20	1590.25	110.30	0.00	[illegible]4.62	463.13	499.50	55.72	7019.46	5564.75	523.09	531.12	263.02	268.09
98	11935.47	1182.46	535.28	419.28	1701.13	1425.06	90.11	0.00	293.02	490.26	524.50	49.53	6710.63	5224.84	491.14	499.12	249.03	250.09
99	11277.87	1136.99	481.42	392.96	1672.97	1271.87	77.2.	0.00	283.10	518.99	550.70	43.34	6429.55	4848.32	455.74	464.59	234.66	229.93
2000	10584.47	1085.01	426.21	365.49	1609.52	1120.11	62.59	0.00	273.89	549.40	578.30	37.14	6107.66	4476.81	420.82	429.55	219.24	210.31
01	9464.02	984.97	354.12	312.81	1574.08	962.54	51.13	0.00	265.99	581.59	607.20	30.95	5730.37	3733.65	350.96	368.43	201.62	166.81
02	8342.03	881.27	285.39	260.39	1541.87	813.50	41.00	0.00	262.91	615.66	637.50	24.76	5364.26	2977.77	279.91	297.67	183.82	113.85
03	7399.39	793.12	237.25	208.85	1539.02	708.25	34.14	0.00	263.33	651.74	699.40	18.57	5153.68	2245.72	211.10	228.30	167.72	60.58
04	6591.22	694.26	195.90	157.62	1538.45	605.57	24.04	0.00	264.44	689.92	702.90	12.38	4885.48	1505.74	141.54	158.93	152.99	5.94
05	5683.56	624.48	173.46	106.53	1518.24	530.99	17.43	0.00	264.88	730.35	738.00	6.19	4710.54	973.02	91.46	103.98	139.26	-35.28

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1) These estimates assume the tax plan is in effect for the whole year; for FY 1982-85 this is Pre SB 524, for FY 1985-05 this is HB 353.

2) FY82 collections of $130.72m are the actual amounts collected or credited to CY82 liability. The estimate for a full year under AS43.20 in FY82 is $242.5m which would result in a difference of $595.12m as presented in column 4 of Table 1. FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.

3) Based on 6/85 70% crude price and production assumptions.

TABLE 4
All Producing Fields
Income Tax Estimates
(mil current FY $)

Fiscal Year	Oil Prod'n (mil B/D)	Wellhead Value 1) (cur $)	Gas Prod'n (mcf/day)	Gas Price ($/mcf)	Total Revenue (cur $)	State Royalty Share	Prod'n Cons Tax	Property Tax	Total Oper'tg Costs	Depre Devel Costs	Amort of Acquis Costs	Windfall Profits Tax	Interest Expense	Explorato Costs (expend)	Admin Cost	Other Deductns	Total Deductns	Total Taxable Income	Total Tax Liability	Total Tax Collectns
82	1.6523	21.293	507000	0.590	12958.93	1564.30	1219.03	113.90	710.80	333.93	0.77	2017.66	119.40	190.90	236.20	148.58	6655.47	6303.46	592.53	627.99
83	1.7006	19.040	503000	0.670	11941.70	1442.73	1090.94	149.15	880.56	511.51	0.98	1018.38	121.20	204.26	252.30	142.39	5822.41	6119.30	575.21	579.54
84	1.7183	17.864	505030	0.670	11327.62	1370.57	1032.93	191.66	1038.34	729.80	1.09	412.33	122.40	218.56	264.90	136.20	5518.78	5808.83	546.03	553.33
85	1.7523	17.463	565091	0.971	11382.33	1362.44	1013.86	234.56	1237.67	824.67	0.80	70.26	127.40	233.86	278.20	130.00	5513.71	5868.61	551.65	550.24
85	1.7523	17.483	565091	0.971	11382.33	1362.44	1377.52	234.56	1237.67	824.67	0.80	69.59	127.40	233.86	278.29	130.00	5807.11	5575.22	524.07	393.05
86	1.7528	16.273	537624	1.097	10626.57	1281.15	1262.27	284.50	1266.70	955.40	0.76	46.77	131.90	247.56	292.10	123.82	5826.16	4800.41	451.24	469.45
87	1.7819	15.105	625000	1.200	10097.40	1212.62	1076.73	315.51	1367.96	1173.51	8.29	29.02	136.10	262.07	306.70	117.63	5977.01	4120.38	387.32	403.30
88	1.7312	15.753	705650	1.306	10290.63	1178.25	765.41	379.38	1468.69	1350.37	32.60	20.25	138.60	277.42	322.00	114.43	6067.15	4223.48	397.01	394.58
89	1.7058	16.843	714549	1.400	10851.82	1218.68	778.54	406.01	1537.02	1521.90	71.31	17.39	139.10	293.68	338.10	105.24	6405.89	4445.93	417.92	412.69
90	1.6392	17.987	797800	1.570	11219.23	1259.40	784.53	420.54	1577.17	1592.66	117.68	16.27	140.30	310.89	355.00	99.05	6657.22	4562.01	428.83	426.10
91	1.5977	19.262	858950	1.705	11135.31	1251.54	749.98	421.30	1562.18	1591.22	150.78	14.42	140.90	329.10	372.80	92.86	6662.66	4472.65	420.43	422.53
92	1.4999	20.945	902485	1.856	11619.35	1305.88	768.16	418.54	1574.96	1611.58	152.28	9.36	141.10	348.38	391.40	86.67	6798.95	4820.40	453.12	444.95
93	1.3515	22.778	920067	1.995	11906.75	1343.04	772.90	412.26	1584.34	1577.52	151.20	3.87	141.20	368.80	411.00	80.48	6822.61	5083.90	477.89	471.69
94	1.2011	24.762	893060	2.149	11555.98	1307.55	718.76	403.58	1521.36	1495.99	145.28	0.14	141.20	390.40	431.50	74.29	6629.92	4926.07	463.05	466.76
95	1.0876	26.856	906549	2.270	11412.40	1294.13	691.55	392.49	1461.42	1452.71	142.96	0.00	142.70	413.28	453.10	68.10	6512.45	4899.95	460.60	461.21
96	0.9635	29.080	920462	2.395	11031.65	1255.86	636.25	377.10	1421.40	1396.56	128.63	0.00	146.70	437.49	475.70	61.91	6337.60	4694.04	441.24	446.68
97	0.8521	31.723	936358	2.562	10742.51	1226.77	588.58	358.16	1386.89	1321.60	110.30	0.00	151.50	463.13	499.50	55.72	6162.15	4580.36	430.55	433.23
98	0.7436	34.548	954349	2.737	10330.41	1182.46	535.28	338.28	1347.18	1156.41	96.11	0.00	156.80	490.26	524.50	49.53	5870.81	4459.60	419.20	422.94
99	0.6457	37.580	943764	2.987	9886.53	1136.99	481.42	318.19	1313.11	1003.22	77.21	0.00	162.20	518.99	550.70	43.34	5605.37	4281.16	402.43	406.62
2000	0.5564	40.823	924739	3.244	9386.09	1085.01	426.21	296.95	1243.34	851.46	62.59	0.00	168.00	549.40	578.30	37.14	5298.40	4087.69	384.24	389.79
01	0.4928	44.381	890963	3.550	8490.22	984.97	354.12	250.50	1205.14	693.89	51.13	0.00	174.60	581.59	607.20	30.95	4933.48	3556.74	334.33	346.81
02	0.3587	48.191	899667	3.847	7572.23	881.27	285.39	204.31	1158.25	544.85	41.00	0.00	180.40	615.66	637.50	24.76	4573.40	2998.83	281.89	295.00
03	0.2855	52.293	879601	4.172	6788.11	793.12	237.25	159.00	1142.58	439.60	34.14	0.00	187.10	651.74	699.40	18.57	4362.51	2425.61	228.01	241.48
04	0.2171	56.904	860541	4.518	5928.48	694.26	195.90	114.00	1128.64	336.92	24.04	0.00	194.00	689.52	702.90	12.38	4092.96	1835.12	172.50	186.38
05	0.1688	61.951	843787	4.896	5324.82	624.48	173.46	89.15	1059.42	262.34	17.43	0.00	201.40	730.35	738.00	6.19	3912.21	1412.61	132.79	142.71

1) These prices are weighted average wellhead values derived from the various values at the N. Slope and Cook Inlet fields evaluated in this study.

TABLE 5
Trans Alaska Pipeline
Income Tax Estimates
(all current FY $)

Fiscal Year	Pipeline Thruput (all B/D)	Tariff ($/B)	Total Revenue	Operat'g Costs/ Year	Amort & Deprec	Uncap Interest	Property Tax	Total Deduction	Net Income	Tax Liability (9.4%)
82	1.5680	6.11	3496.88	229.00	268.65	601.29	162.00	1260.94	2235.94	210.18
83	1.5300	5.93	3528.05	220.00	268.65	554.84	157.40	1200.89	2327.16	218.75
84	1.6536	6.01	3627.42	221.00	268.65	491.73	166.00	1147.38	2480.04	233.12
85	1.7140	6.00	3753.66	211.50	268.65	438.15	162.00	1080.30	2673.36	251.30
86	1.7173	6.00	3760.80	210.96	268.65	409.86	155.77	1045.24	2715.56	255.26
87	1.7503	6.00	3833.22	232.48	268.65	381.77	149.54	1032.44	2800.78	263.27
88	1.7037	6.00	3731.16	246.48	268.65	351.68	143.31	1010.12	2721.04	255.78
89	1.4818	6.00	3683.10	259.65	268.65	327.01	137.08	992.39	2690.71	252.93
90	1.6181	6.00	3543.66	277.26	268.65	302.34	130.85	979.10	2564.56	241.07
91	1.4892	6.00	3261.30	293.06	268.65	277.65	124.62	963.98	2297.32	215.95
92	1.4238	6.00	3118.02	305.39	268.65	252.44	118.38	944.86	2173.16	204.28
93	1.3376	6.00	2929.26	316.94	268.65	226.53	112.15	924.27	2004.99	188.47
94	1.1808	6.00	2603.40	325.20	268.65	204.01	105.92	903.78	1699.62	159.76
95	1.0758	6.00	2355.90	333.10	268.65	186.27	99.69	887.71	1468.19	138.01
96	0.9520	6.00	2084.88	340.60	268.65	169.75	93.46	872.46	1212.42	113.97
97	0.8410	6.00	1841.70	348.31	268.65	153.12	87.23	857.31	984.39	92.53
98	0.7329	6.00	1605.06	353.95	268.65	136.22	81.00	839.82	765.24	71.93
99	0.6353	6.00	1391.34	359.86	268.65	120.90	74.77	824.18	567.16	53.31
2000	0.5472	6.00	1198.38	366.18	268.65	105.89	68.54	809.26	389.12	36.58
01	0.4447	6.00	973.80	373.94	268.65	91.99	62.31	796.89	176.91	16.63
02	0.3515	6.00	769.80	383.62	268.65	82.51	56.08	790.86	-21.06	-1.98
03	0.2791	6.00	611.28	396.44	268.65	76.23	49.85	791.17	-179.89	-16.91
04	0.2115	6.00	463.14	409.81	268.65	70.44	43.62	792.52	-329.38	-30.96
05	0.1638	6.00	358.74	428.82	268.65	63.48	37.38	798.33	-439.59	-41.32

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1) No gas production considered (26 TCF).
2) No TAPS settlement.
3) Some account of total crude taken off at N. Pole i.e. does not go to Valdez.
4) Based on 6/85 70% case price and production assumptions.
5) Seal Is. excluded.

ASSUMPTIONS:

Property taxes per AS43.56 @2% gross.

TABLE 6
WINDFALL PROFITS TAX DEDUCTION
(mil current FY $)

DEDUCTION FROM FY TAXABLE INCOME

Fiscal Year	Sadlerochit	Cook Inlet	Total	Impact on FY Tax Liability (Total * .094)
Under Pre-SB 524				
	a)			
82	1750.61	267.05	2017.66	189.66
83	848.78	169.60	1018.38	95.73
84	289.25	123.08	412.33	38.76
85	8.93	61.33	70.26	6.60
Under HB 353				
	b)			
85	8.51	61.09	69.60	6.54
86	-0-	46.77	46.77	4.40
87	-0-	29.02	29.02	2.73
88	-0-	20.35	20.35	1.91
89	-0-	17.39	17.39	1.63
90	-0-	16.27	16.27	1.53
91	-0-	14.42	14.42	1.36
92	-0-	9.36	9.36	.88
93	-0-	3.87	3.87	.36
94	-0-	.14	.14	.01

Note:

1/ Based on 6/85 70% case price and production assumptions.

2/ Windfall Profits Tax is phased out and no longer in effect in FY 1995 and thereafter.

3/ The reason for the slight difference in FY 85 under Pre-SB 524 compared to HB 353 is the difference in the Oil Severance Tax law and thus, the severance tax adjustment under the WPT.

a) For FY 1982 through 1985, these impacts are includ d in Tables 3 and 4 under the Pre-SB 524 separate accounting corporate tax. If the WPT was not a deduction for those years, the total tax liability columns would have been increased by these amounts.

b) For FY 1982 through 2005, these impacts are not included in Tables 3 and 4 under the HB 353 separate accounting corporate tax. If the WPT was a deduction for these years, the total tax liability columns would be reduced by these amounts. In FY 1985, the reduction would be approximately one half the amount because HB 353 goes into effect midway through the fiscal year.

V.

This section will present comments and conclusions relative to HB 353 based on the analysis outlined and summarized in preceding sections.

As to the feasibility analysis performed relative to the impact of HB 353 on development and production of the "marginal" North Slope fields, the following qualifications should be noted:

The feasibility analysis performed in the Petroleum Revenue Forecasting Model tests the real after tax discounted cash flow rate of return from a field against an assumed "hurdle" real rate of return to determine feasibility. If the rate of return for the field given projected production, prices, development costs, operating costs and tax rates exceeds the hurdle rate, development of the field is deemed feasible.

There are three potential problems with applying this quantitative analysis to the "marginal" North Slope fields and then drawing conclusions about the actual timing and magnitude of their development. The first is the "hurdle" rate used in the model may not be the same as the "hurdle" rate actually used by the corporations with lease rights to develop the field. The second is that the model analysis assumes no capital budget constraint. In reality, the corporations have a limited amount of capital to invest in the development of fields in Alaska and

elsewhere in the world. Even though development of a field in Alaska may be projected by the corporation to provide an acceptable rate of return given the corporation's actual "hurdle" rate, there may be other even more attractive projects elsewhere which would be developed instead, given a limited capital budget. Finally, there may be non-quantifiable judgmental factors which the corporations consider in making their investment decisions. These types of judgmental considerations are necessary to distinguish between two investment alternatives which are projected to be equally attractive on a quantitative basis.

Regardless of these three potential problems in applying the feasibility model to analyze when and at what level a field will actually be developed, the model is useful in analyzing the relative effect of alternative tax structures on rates of return and feasibility of development given projected production, costs and prices. Here, as discussed earlier, our analysis indicated the impact of the HB 353 tax structure with respect to Petroleum Corporate Income Tax and Petroleum Severance Tax on the feasibility of development was relatively insignificant. The future of oil prices will have a much more significant effect on the feasibility of development for these fields.

As to the revenue impact of HB 353, the analysis indicated that under all alternative price and production scenarios examined, cumulative revenues from income and severance taxes for FY 1985 through FY 2005 were greater under HB 353 than under the current tax structure. The absolute and percentage gain, however, varied significantly between scenarios.

For example, cumulative revenues from income and severance taxes for FY 1985 through FY 2005 were 12.12 percent higher under HB 353 than under current law given the Mean case price and production scenario, 8.38 percent higher given the 30 percent scenario and 17.39 percent higher given the 70 percent scenario.

This is because the tax structure proposed by HB 353 is more sensitive to price and production changes than the current tax structure. The severance tax under HB 353 is slightly less sensitive to price and production changes than the current severance tax simply because it is levied at a lower maximum rate, 12.25 percent as compared to 15 percent under the current law. However, this is more than offset by the income tax which is significantly more sensitive under HB 353 than under current law resulting in greater overall revenue sensitivity under HB 353.

The cumulative revenues collected from income taxes for FY 1985 through FY 2005 under the current apportionment tax structure were projected to be 5.04 percent lower given the 30 percent scenario as compared to the Mean scenario and 16.94 percent higher given the 70 percent scenario as compared to the Mean scenario. The cumulative revenues collected under the proposed HB 353 separate accounting income tax were projected to be 14.52 percent lower given the 30 percent scenario compared to the Mean scenario and 30.83 percent higher given the 70 percent scenario compared to the Mean scenario. The reason for this

is under separate accounting, revenue collections are directly dependent upon the level of production and wellhead values in Alaska. Under apportionment, however, revenue collections are dependent on both worldwide income and the level of Alaska activity compared to worldwide activity as measured by apportionment factors. Therefore, the apportionment tax structure is less directly sensitive to changes in Alaska production and wellhead values. Also, it should be noted that a given percentage change in worldwide oil prices results in a greater percentage change in Alaska wellhead values due to the fixed transportation cost differential which exists between the two. For example, if world crude prices were $20.00 per barrel and there was a total fixed transportation cost of $10.00 per barrel to get Alaska crude to market, the wellhead value of Alaska crude would be $10.00 per barrel. If world prices were to increase by 5 percent to $21.00 per barrel, Alaska wellhead value would increase from $10.00 to $11.00 per barrel which would represent a 10 percent increase. Therefore, alternative price scenarios result in greater percentage differences in Alaska activity and income upon which separate accounting is based than in worldwide activity and income upon which apportionment is based.

The HB 353 proposal, because it is more sensitive to oil prices, has the potential for greater upside gain should prices increase and the potential for greater downside risk should prices decrease when compared to the current tax structure.

It should be noted that by FY 2005, the revenues collected under apportionment were projected to be greater than under separate accounting given all alternative scenarios. This is because under apportionment, worldwide income was assumed to increase over time and was only partially offset by declining apportionment factors as Alaska activity declined. Under separate accounting, collections declined directly over time with declining Alaska activity and income.

It is also interesting to note that by FY 2005, collections under the current apportionment tax are approximately equal given both the Mean and 70 percent assumptions. This is because even though the 70 percent case assumes a higher long-run worldwide apportionable income growth rate it also assumes a higher growth rate in worldwide production which acts to reduce the apportionment factor at a faster rate thus offsetting the higher income growth rate. As noted earlier, however, over the entire period from FY 1985 through FY 2005, the 70 percent case assumptions resulted in revenue collections which were 16.94 percent higher than the Mean.

In comparing revenue collections under separate accounting in FY 2005 given Mean and 70 percent scenario assumptions, the 70 percent case generates less revenue than the Mean case. The reason for this is that under the 70 percent scenario, development of fields in Alaska occurs earlier and at a more rapid pace. Therefore, by FY 2005, production

under the 70 percent scenario is less than production under the Mean scenario. As noted earlier, however, over the entire period from FY 1985 through FY 2005, the 70 percent case assumptions resulted in revenue collections which were 30.83 percent higher than the Mean.

A number of revisions have been made to the analysis compared with the preliminary analysis previously presented to the Legislature during the 1985 legislative session. The previous analysis was based on March, 1985 Mean case price assumptions whereas this analysis is based on June, 1985 price assumptions which are significantly lower in the Mean case. This analysis includes two additional marginal fields, West Sak and Point Thompson which were not included before. The March analysis included projections only through FY 1995. Total projected cumulative revenue collections from both income and severance taxes given Mean case assumptions under both current and proposed tax structures are lower now than in March.

Severance taxes projected under both laws are lower due to lower price and wellhead value projections in spite of somewhat higher production from the inclusion of the two additional fields in the analysis.

Income tax projections under the current apportionment law are lower due primarily to lower expectations for long-run worldwide apportionable income growth rates. Income tax projections under the proposed HB 353 separate accounting law are lower due to lower wellhead

values and hence, gross revenues. The inclusion of additional fields does not result in enough additional production to offset the effect of lower wellhead values on gross revenues, and the additional fields included also had deductions associated with them which reduced net taxable income even more. Also, as discussed earlier, separate accounting deductions primarily operating cost estimates, have been revised upward since March.

The revisions since March have resulted in a greater downward revision in projected collections under the current income and severance tax laws than under the proposed HB 353 income and severance tax laws. Therefore, the absolute and percentage revenue gain from HB 353 is projected to be greater now than in March. Total cumulative revenues collected for FY 1985 through FY 1995 were projected to be 13.46 percent higher under HB 353 than under current law given the Mean case assumptions in March and now are projected to be 16.79 percent higher for the same period (1985-1995) given the Mean case assumptions.

It should also be noted that due to the revision in the operating cost deduction, the estimates of revenues which would have been collected under the pre-SB 524 separate accounting corporate tax for FY 1982 through FY 1985 are lower now than in March.

376-3111 home

Bill + Mike Kozowski:

Bill has done DNR's rsv estimates -

wd need a thorough analysis to see if drilling is legitimate -

plan of dev't req's dev't of ent area - West End Gillen e.g. -
(like the lease) - they are now being diligent in dev't, partly -

you don't mk rsvs - you borrow

Chat

Saxon's group as lessor + unit signator gets a plan of dev't w/ annual oper'g plan updates.

reservoir study - Van Poolen - approp'n in '78 - initially in 72 w/ a 2-dimensional model - cost about $800k - kept Van Poolen on for updates till Dec 84 - state library shd hv copies - legislative library -

don't see any need to update the study - will need it feel / is dev'd -

exp'd declined in 2/3d qtr of '89 -

87 decline did not occur bec. no gas sales - no redn of pressure

~~##~~ 26'3

'90 decline will be steeper bec. of ~~[illegible]~~ delayed decline -

160 → 80-acre spacing -

---

changing the shape of the curve vs. the area under it -
is the ELF causing ~~new~~ producn of add'l volume or just expedited recovery?

3/22 Kotowski

1) every yr. a progress report or plan of dev't or dev't of acreage - what they did to satisfy prior plan, then propose work for up coming yr - # wells + other facilities

2) Kuparuk + Prudhoe plans hv been pretty lengthy -

3) maximizing recovery - AOGCC is more attuned - thru. model controls - computer models match performance - same projects of proden rates etc. (AOGCC) - drilling permits e proden history / monitoring of pressure / more tech'l on reservoir -

4) DNR > conc'd w/ maxg recy - what are lessees doing to define the reservoir - "optimizing proden" - (inst.)

V w/ Bill -

3/23 who regulates proden rates? AOGCC/DNR both hv regs -

DNR - AS 38.05.180 (q)

AOGCC - AS 31.05.030 (e)(6)

Prudhoe P.O.D

2 diff plans

1) spec. reservoirs - exh. (e) for unit agmt

perm - Triassic Eileen, Sag, Shublik, Sadlerochit

2) p.o.d for lands outside initial participating area -

Lisburne / Kuparuk (part) etc.

"funky"

since approval of unit agmt of p.o.d / perm - Triassic -

Mike hasn't read yet - pretty broad this -

so just get prog reports for. opers for past yr

Kotowski (2)

June 1 86 - May 31 87 - last one filed - shd get a new one by 6/1/88 - They file by 6/1/88 - so we don't know what they've done since ELF took effect for Prudhoe -

dev't plans + rig schedules are avail. fr. companies have POD fr. Osborne -

9 pages for 86-87 -

get back to 1980 -

plan of dev't for unit agmt - 11 pages -

prices / drilling effect on fluid recov / waterflood + drilling to optimize oil -

ELF effect "icing" on the cake -

prob'y hasn't expanded drilling much fr. what wd be expd w/ these prices for oil -

[waterflood modelling - are you using oil beh? do you need to change spacing of wells?

Δ well permitting chart ③

→ Littleton, CO.
Van Poolen – companies do th. own modelling =

3/23 Chat re well pmts 279-1433

how long ahead of time -
usu a week to 10 days -
statute says deliver quickly -
AS 31.05.090 - form provided by

consvn orders - 280 since st'hd -

What does OGCC look at in pmts?
contrary to law, reg or order by OGCC
comply w/ ~~field~~ pool rules - via public hrg. -

pool rules - well-spacing. etc. - => so indiv. pmts shd comport w/ rules -

pmt stats
-> monthly bulletin - The State

-> want max that tech'y permits -
offtake limits -
well-spacing -
maximizing ult. recov'y.
safety as it relates to waste only -

Prudhoe - 80
↓
145

Kuparuk - one
Lisburne -
Endicott -

-> Petroleum Info Svc - drill rigs -

Chart-2

1 (now) vs 2 (rigs) @ Kuparuk - ARCO --
SOHIO kept 2 rigs in West end +2 in Endicott
1 in Lisburne from 2

A is hist'ly low now

there has not bn much Δ in drilling in
the past year.

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 Porcupine Drive
Anchorage, Alaska 99501

Re: THE REQUEST OF SOHIO ALASKA PETROLEUM COMPANY to present testimony to determine pool rules for the Endicott Oil Pool.	Conservation Order No. 202 Endicott Field Endicott Oil Pool September 20, 1984

IT APPEARING THAT:

1. Sohio Alaska Petroleum Company requested the Alaska Oil and Gas Conservation Commission to hold a public hearing in order to receive testimony for the establishment of pool rules for the development and exploitation of the Endicott Oil Pool.

2. Notice of the public hearing was published in the Anchorage Times on July 24, 1984 and in the Anchorage Daily News on July 25, 1984.

3. A public hearing was held in the Municipality of Anchorage Assembly Room, 3500 East Tudor Road, Anchorage, Alaska on August 22, 1984.

4. Members of the staff of Sohio Alaska Petroleum Company presented testimony and the hearing record was closed at the end of the public hearing.

FINDINGS:

1. Hydrocarbons are trapped in the Kekiktuk Formation, a part of the Endicott Group.

2. There has been widespread usage of "Endicott" as the field name and the field and pool should be named Endicott Field and the Endicott Oil Pool.

3. The vertical limits of the pool may be defined by the accumulations in the Sohio Alaska Petroleum Company Sag Delta No. 4 well which appears to be a typical and representative well.

4. Well control and structural interpretation are adequate to reasonably define the areal limits of the accumulation

5. The pool is bounded by several major faults and there appear to be numerous minor faults within the field limits.

6. The areal extent of the hydrocarbon-bearing reservoir is about 8600 acres.

7. A gas-oil contact has been determined to be a planar horizontal surface fieldwide at 9855 feet subsea.

8. The oil-water contact is assumed to be a planar horizontal surface fieldwide at 10,192 feet subsea.

9. A spacing pattern denser than one well per 160 acres may be necessary to recover the maximum amount of oil.

10. The field is characterized by faulted structural patterns, inconsistent lithology and changing lateral and vertical reservoir characteristics.

11. To adequately evaluate the effectiveness of the reservoir depletion plan, the reservoir pressure, the gas-oil ratio, the gas-oil contact, and the productivity profile of wells should be monitored on a regular and continuous basis soon after regular production commences.

12. Enhanced recovery methods must be employed to achieve maximum recovery. Studies have indicated that a full field waterflood project started within two years after initial production will greatly increase recovery and will not preclude other additional enhanced recovery projects in the future.

13. Studies indicate the ultimate recovery from the reservoir is sensitive to the daily offtake rate.

14. All wells will be drilled from man-made gravel islands with a surface grade approximately 22 feet above the original mud line or ocean floor.

15 The contribution of intervals open to the wellbore in each producing well may be determined by running productivity profile surveys.

16. Initial reservoir and bubble point pressures are estimated to average 4840 psig. The reservoir temperature ranges from 200 to 225 degrees Fahrenheit.

17. Studies indicate that all produced gas, excepting volumes used for lease purposes, should be injected into the gas cap to assist in reservoir pressure maintenance.

18. Structural casing set through the island gravel and below the mud line appears necessary to conduct wellbore operations.

19. Conductor casing set and cemented a minimum of 75 feet below the island surface should provide adequate anchorage for a diverter system.

20. The effects of permafrost thaw-subsidence and freeze back loadings can be mitigated by setting and cementing surface casing of sufficient strength at least 500 feet below the base of the permafrost but no more than 2700 feet true vertical depth.

21. Several casing types and grades that are approved for use as surface casing in the Prudhoe Bay Field and the Kuparuk River Field are adequate for this field.

22. Perforation of cemented casing or liners, slotted liners, wire wrapped screen liners, and open hole completions appear to be equally effective completion techniques.

23. Unless the pool is operated under a unit agreement, the pool management program contemplated in the testimony can not be undertaken, without negatively impacting correlative rights.

24. Statewide regulations presently in effect govern field operations except as modified by this conservation order.

NOW, THEREFORE, IT IS ORDERED THAT the rules hereinafter set forth apply to the following described area referred to in this order as the affected area:

UMIAT MERIDIAN

T11N	R16E	Sections 1, 2, and 12.
T11N	R17E	Sections 3, 4, 5, 6, 7, 8, 9, 10, 13, 14, 15, 16, and 17.
T12N	R16E	Sections 25, 26, 27, 34, 35, and 36.

That portion of those lands in the S½ S½, NW¼ of Block 653 lying north of the south boundary of Sections 22, 23, and 24; T12N, R16E, U.M., Alaska (being identical with line 6-7 on Block 653) and those lands in the S½ SW¼ NE¼ of Block 653 lying north of the south boundary of Section 24, T12N, R16E, U.M., Alaska and east of the west boundary of Section 30, T12N, R17E, U.M., Alaska and those lands in the SW¼ SE¼ NE¼ of Block 653 and those lands in the SE¼ of Block 653 lying east of the west boundary of Sections 30 and 31, T12N, R17E, U.M., Alaska and those lands in the SW¼ SW¼ of Block 654 and

those lands in the SW¼ NW¼ SW¼ of Block 654 and those lands in the SW¼ SE¼ SW¼ of Block 654 and those lands in Block 697 lying in T12N, R17E, U.M., Alaska being the northeast portion of Block 697 and those lands in the NW¼ of Block 698 lying north of the south boundary of Sections 31, 32, and 33, T12N, R17E, U.M., Alaska and those lands in NW¼ NW¼ NE¼ of Block 698 lying north of the south boundary of Sections 33 and 34, T12N, R17E, U.M., Alaska which are within the offshore three-mile arc lines and which are all listed as state area on the "Supplemental Official O.C.S. Block Diagram" approved October 19, 1979 and December 9, 1979, respectively.

That portion of those lands in the S½ and S½ N½ of Block 698 lying east of the west boundary of Sections 2 and 11, T11N, R17E, U.M., Alaska (being identical with the line 4-5 Block 698) and lying north of the south boundary of Section 11, T11N, R17E, U.M., Alaska (being identical with line 5-6 in Block 698) and the SW¼ NW¼ of Block 699 and those lands in the SW¼ of Block 699 lying north of the south boundary of Sections 11 and 12, T11N, R17E, U.M., Alaska and those lands in the SW¼ NW¼ SE¼ of Block 699 and those lands in the SW¼ NW¼ SE¼ of Block 699 and those lands in the SW¼ SE¼ of Block 699 lying north of the south boundary of Section 12, T11N, R17E, U.M., Alaska and east of the west boundary of Sections 7 and 18, T11N, R18E, U.M., Alaska which are within the offshore three-mile arc lines and which are all listed as state area on the "Supplemental Official O.C.S. Block Diagram" approved October 4, 1979 and December 9, 1979, respectively.

Rule 1 FIELD AND POOL NAME.

The field is named the Endicott Field. The hydrocarbons contained within the Kekiktuk Formation constitute a reservoir named the Endicott Oil Pool.

Rule 2 POOL DEFINITION.

The Endicott Oil Pool is defined as the accumulations of oil and gas that are common to and which correlate with the accumulations found in the Sohio Alaska Petroleum Company Sag Delta No. 4 well between the measured depths of 11,496 and 12,812 feet.

Rule 3 WELL SPACING.

Nominal 40 acre drilling units are established for the pool within the described area. Each drilling unit shall conform to quarter-quarter governmental sections as projected. No more than one well may be drilled into and produced from each drilling unit. The pool may not be opened in a well closer than a 1000 feet to any well opened to the pool. The pool shall not be opened in any well closer than 500 feet to the exterior boundary of the affected area. The Commission may administratively approve modifications to well spacing when justified.

Rule 4 CASING AND CEMENTING REQUIREMENTS.

a) Structural casing shall be set by driving or jetting to a sufficient depth below the mud line to ensure support of drilling fluid returns to the surface while drilling hole for a conductor string.

b) Conductor casing to provide for proper anchorage shall be set at least 75 feet below the island surface and sufficient cement shall be used to fill the annulus behind the pipe to the island surface. Cement fill shall be verified by observation of cement returns. The cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

c) Surface casing, to provide for proper anchorage, for preventing uncontrolled flow and to protect the well from the effects of permafrost thaw-subsidence or freeze back loadings, shall be set at least 500 measured feet below the base of the permafrost but not below 2700 feet true vertical depth. Sufficient cement shall be used to fill the annulus behind the casing to at least the mud line.

d) Surface casing types and grades approved for use include:

1)	13-3/8 inch,	72 pounds/foot,	L-80 Buttress;
2)	13-3/8 inch,	72 pounds/foot,	N-80 Buttress;
3)	13-3/8 inch,	68 pounds/foot,	MN-80 Buttress;
4)	10-3/4 inch,	45.5 pounds/foot,	K-55 Buttress;
5)	10-3/4 inch,	45.5 pounds/foot,	HF-ERW Arctic Grade, J-55 Buttress;
6)	9-5/8 inch,	36 pounds/foot,	K-55 Buttress;
7)	9-5/8 inch,	40 pounds/foot,	K-55 Buttress;
8)	9-5/8 inch,	36 pounds/foot,	HF-ERW Arctic Grade, J-55 Buttress;
9)	9-5/8 inch,	40 pounds/foot,	HF-ERW Arctic Grade, J-55 Buttress;
10)	9-5/8 inch,	47 pounds/foot,	L-80 Buttress.

e) The Commission may administratively approve additional types and grades of surface casing upon a showing that the proposed casing and connection can withstand the permafrost thaw-subsidence and freeze back loadings which may be experienced. Evidence submitted to the Commission shall include:

1) full scale tension and compression testing; or
2) finite element model studies, or
3) other types of axial strain data acceptable to the Commission.

f) Alternate means for maintaining the integrity of the well from the effects of permafrost thaw-subsidence and freeze back may be administratively approved by the Commission upon application and presentation of data which show the alternatives are appropriate, based upon accepted engineering principles.

Rule 5 COMPLETION PRACTICES

Wells completed for production from the Endicott Pool may utilize casing strings or liners cemented through the productive intervals and perforated, slotted liners, screen wrapped liners or open hole methods, or combination thereof. The Commission may administratively approve alternate completion methods where appropriate.

Rule 6 PRESSURE SURVEYS.

a) Prior to regular production, a pressure survey shall be taken on each well.

b) The datum for all pressure surveys is 10,000 feet subsea.

c) After regular production commences in each governmental section, a pressure survey shall be taken within six months and again within 12 months on at least one well in the section.

d) Within 12 months after regular production from the pool starts, the operator will submit to the Commission for approval a key-well program setting forth the long term pressure monitoring program for the pool.

e) Pressure survey, as used in this rule, means either a static bottomhole pressure survey or a transient pressure survey.

f) Data from all pressure surveys shall be filed with the Commission on Form 10-412 within 45 days after the survey is taken.

g) The Commission, by administrative order, may amend the key well pressure monitoring program if it is found to be inadequate or impractical.

Rule 7 GAS-OIL RATIO TESTS.

a) After regular production from a well has commenced, a gas-oil ratio test will be taken within four months and each six months thereafter.

b) Gas-oil ratio tests shall be a minimum of four hours duration unless otherwise administratively approved by the Commission.

c) Gas-oil ratio tests will be reported on Form 10-409 and submitted within 45 days after the tests are taken.

Rule 8 GAS VENTING OR FLARING.

a) The venting or flaring of gas is prohibited except as may be authorized by the Commission for facility safety, cases of emergency or operational necessity.

b) Infrequent operations where flaring is necessary, such as the initial commissioning of facilities, plant start-ups after maintenance or tie-in shutdowns and other special activities, may be administratively approved by the Commission upon written request.

c) The Commission will administratively set volumes for safety flares upon receipt of a written request and accompanied by adequate data to support the request.

Rule 9 GAS-OIL CONTACT MONITORING.

a) A compensated neutron log shall be run in each well prior to regular production.

b) A compensated neutron log shall be run in one well per governmental section within 12 months after regular production starts.

c) A key-well gas-oil contact monitoring program will be submitted to the Commission for approval within 12 months after regular production from the pool commences and will constitute the long term gas-oil contact monitoring program.

d) Compensated neutron logs will be submitted within 45 days after they are taken.

Rule 10 GAS-OIL RATIO.

a) The gas-oil ratio in a well will have no upper limit if all gas produced from the pool except quantities used in lease operations or administratively approved for other purposes by the Commission, is injected into the Endicott Oil Pool.

Rule 11 PRODUCTIVITY PROFILES.

a) An appropriate log to establish the productivity or injectivity profile of the intervals open to the wellbore will be run in each well within 12 months after regular production or injection commences.

b) A program to monitor well productivity and injectivity will be submitted to the Commission for approval at least three months before water injection begins.

c) Additional productivity surveys may be required by administrative order if underground waste of hydrocarbons appears imminent.

d) Productivity surveys will be submitted to the Commission within 45 days after the date of the survey.

Rule 12 FIELD-WIDE WATERFLOOD PROJECT.

a) A field-wide waterflood project is approved for the pool area.

b) The field waterflood project must be started within two years after regular production from the pool has started.

c) The waterflood plan will be submitted to the Commission at least three months before actual water injection begins.

d) All applications for permits necessary to implement the waterflood project shall be timely submitted for approval.

Rule 13 POOL OFFTAKE RATE.

a) The maximum calendar quarter average offtake rate from the pool is 125,000 barrels of oil per day. Calendar quarter average offtake rate means the daily average rate determined by dividing the total volume of oil produced in a calendar quarter by the number of days in that calendar quarter.

b) The maximum calendar quarter average offtake rate of 125,000 barrels of oil per day may be exceeded for the purpose of making up a shortfall in the allowable volume of oil produced in a previous calendar quarter providing that the offtake rate for any day does not exceed one hundred ten percent (110%) of the calendar quarter average offtake rate.

c) For the purpose of providing for reasonable operating flexibility, the calendar quarter offtake volume may be exceeded. The volume of oil determined by multiplying 125,000 barrels by the number of days in that calendar quarter establishes an allowable calendar quarter offtake volume. A calendar quarter offtake volume may not exceed the allowable calendar quarter offtake volume by more than one percent (1.0%) without prior approval of the Commission. Volumes of oil exceeding the allowable calendar quarter offtake volume shall be zeroed out in the following calendar quarter by producing at rates lower than the maximum calendar quarter average offtake rate until that volume of oil produced in excess of the previous allowable calendar quarter offtake volume is offset. The volume of oil produced in calendar quarters in excess of the allowable calendar quarter average offtake rate for the purpose of recovering a shortfall in an allowable calendar quarter offtake volume as provided for by (b) above is not given consideration when making a determination

for the purpose of this subsection (c).

d) Gas offtake is not permitted because the reservoir depletion program governed by this order requires that produced gas be injected into the Endicott Oil Pool. At anytime, upon proper petition and after public hearing, the Commission will consider the merits of issuing an order establishing a gas offtake rate. That order would provide for appropriate amendments to the pool depletion program governed by this order to ensure that a loss in ultimate recovery will not occur.

Rule 14 UNITIZATION.

a) Oil and gas leases overlying the affected area shall be unitized and a participating area established for the Endicott Pool prior to the commencement of regular production from the pool.

b) Should unitization and the establishment of a participating area not be accomplished prior to regular production from the pool, this order is null and void. Upon petition and after public hearing, the Commission will issue an order setting forth pool rules governing competitive lease production methods that will ensure the protection of correlative rights and the maximum ultimate recovery from the pool or issue an order mandating pool unitization.

DONE at Anchorage, Alaska and dated September 20, 1984.

C. V. Chatterton, Chairman
Alaska Oil and Gas Conservation Commission

ALASKA OIL AND GAS CONSERVATION COMMISSION

Harry W. Kugler, Commissioner
Alaska Oil and Gas Conservation Commission

Lonnie C. Smith, Commissioner
Alaska Oil and Gas Conservation Commission

go0038hLd
Utermohle

A M E N D M E N T

Offered in the HOUSE

By Cotten

TO: CSHB 390 (Finance)

Page 2, line 1, after (a), through line 8:

Delete all material.

Insert "The distribution of the income and realized capital gains of the endowment is subject to AS 37.07. The net annual realized capital gains of the endowment may be equally divided between the income and the principal of the endowment. Upon application of the foundation's board of directors or its authorized representative, after authorization under AS 37.07 the Alaska Permanent Fund Corporation shall pay to the foundation the income appropriated."

SAM
I did this for Cliff - I guess he's thinking now of sending it to the Daily News

N

GETTING ALASKA'S SHARE OF OIL REVENUES

by Cliff Davidson (1)

Alaskans own Prudhoe Bay, the largest and most prolific oil field in U.S. history. We have derived tremendous benefits from its development: the Permanent Fund, our schools, many municipal improvements, and government services for children, the elderly and the disabled.

However, our share of the revenue from this field has recently been reduced, while the major oil companies are increasing their share and proclaiming their profitability in a tough oil market. For this fiscal year, about $185 million has been directly transferred from Alaska to the corporate treasuries of several major international oil companies.

All over the state, people who need school improvements and municipal services are wondering why the Legislature allowed a reduction in oil and gas taxes when our state revenues are in precipitous decline.

The answer to the question is that the Legislature scheduled the tax break back in 1981, when oil prices were rising and it was thought that Prudhoe Bay would be in

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1 - Cliff Davidson represents Kodiak in the State House and is a member of the House Resources Committee.

decline by 1987. Today it is clear that the industry will continue to operate, quite profitably, if the tax regime is restored. Yet the State Senate has refused to act on the oil tax bill, despite Governor Cowper's support for it and the State House's.

Last year the House passed a bill, introduced at the Governor's request, that did two important things:

* prevented large tax breaks for giant oil fields like Prudhoe and Kuparuk, where tax incentives aren't needed, and

* provided a new tax incentive for production from every other known field in Alaska, including marginal fields such as Endicott, Lisburne, and Milne Point, which was shut down in 1987 because it was uneconomic.

This approach makes sense. Forbes magazine recently reported that Atlantic Richfield is one of the most profitable oil companies in the world, and guess where the company gets 67% of its oil? From Kuparuk and Prudhoe Bay. Tax breaks are simply unnecessary for these oil fields.

The chief executive of Atlantic Richfield recently boasted that the company's profits are the "best in the

industry." The company has also publicly reported that it increased its Alaska production while reducing production from other sources. These aren't the actions of a company producing from a marginal property.

Meanwhile, British Petroleum last year completed its acquisition of Standard Oil. Now it owns 100% of that company, which got 98% of its oil production from Alaska. And Kuwait's national oil company has purchased more than 20% of BP. These aren't the actions of corporations worried about the profitability and potential of Alaska oil and gas production.

Some industry representatives claim that the tax break has encouraged more drilling on the North Slope. No proof has been offered that the new drilling provides Alaskans extra jobs or that the long-term production of Prudhoe and Kuparuk is being increased. Instead, we might just be seeing the hastier depletion of oil and gas reserves.

Industry representatives also talk about "tax stability." They imply that there was a compact between the 1981 Legislature and the oil and gas industry to install a tax break in 1987. But they neglect to mention that there were other issues -- legislative instability, legal battles, and inaccurate production projections -- that influenced the

1981 Legislature. They also don't seem to realize that today's legislators need to deal with today's problems.

In fact, it's clear that the industry actually supports tax changes when those changes benefit the industry. In 1981 the industry came to the Legislature (in a time of oil price inflation) and asked for tax breaks. The Legislature responded by instituting a new "unitary" tax system. Since that time, Alaskans have foregone billions of dollars worth of revenue that would have been collected under the former system.

are we sure of this?

Alaskans have a choice here: shall we continue to forfeit tax revenues that could be put to many purposes around the state, or shall we go ahead and collect taxes that won't harm the industry and will bring us back to where we stood a year ago? I'm strongly supportive of Governor Cowper's effort to rescind the oil tax break, and I'm glad that the House and the Governor are working together on a tax system that will truly serve the interests of all Alaska.

How does the 1987 oil tax break affect Alaskans?

* It has reduced state revenues by about $185 million this fiscal year. This money goes directly to the corporate treasuries of major oil companies.

* It will cost about $1.2 billion over five years.

What is wrong with the 1987 tax break?

* It was scheduled in 1981 on the basis of inaccurate assumptions about the legality of separate accounting, oil prices, and the projected decline of Prudhoe Bay

* It enhances the profitability of companies who claim their profits are "the best in the industry," who are searching around to buy new companies overseas, and who have themselves been partly bought up by the Kuwaiti national oil company.

* It provides unnecessary tax breaks for profitable fields but does not adequately enhance the profitability of truly marginal fields such as Milne Point.

Does the tax break pay off for Alaska?

* It removes $185-225 million per year from the state budget and the Alaska economy. This probably equates to about 4,000 jobs (20 jobs per million dollars).

* It might create some incentive to increase drilling activity on the North Slope, but this has not been proven. From 1/87 to 2/88 the North Slope rig count increased by three. (Usually there are 50-200 jobs per rig, many of which are taken by outside labor.)

* ARCO announced in 7/87 that it would be adding a rig (restoring one removed in 3/87) and that increased development activity was "strictly the result of higher oil prices."

* In 2/88 ARCO announced North Slope enhanced recovery plans that will cost $3 billion over ten years. They had already made the same announcement in 5/87. The tax break might not have had any effect at all on enhanced recovery plans; it might lead to hastier rather than increased oil production.

What can be done?

* The Senate can pass CSHB 164 (Fin), converting to a field-based economic limit factor that will eliminate

1987 tax break and enhance the profitability of all Alaska fields except Prudhoe and Kuparuk.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version: CS HB 164 (FIN) AM
REQUEST
Publish Date:

Revision Date: April 14, 1987
Title: An Act Relating to the Oil and Gas Production Tax
Sponsor: Rules/Governor
Requestor:

Agency Affected:
BRU:
Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	680	88140	10804	11800	11576	12317

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: Attach a separate page if necessary

This bill would change the Economic Limit Factor (ELF) to introduce field size as a consideration in establishing the effective severance tax rate on oil production. Fields producing in excess of roughly 120,000 barrels per day will have a higher rate than currently calculated. Other fields will have a lower rate.

Prepared By: Charles L. Logsdon (Vincent Wright for) Phone: 276-5364
Division: Commissioner's Office Date: April 20, 1987

Approved by Commissioner: Hugh Malone Date: April 21, 1987
Agency: Department of Revenue

Distribution (by Agency preparing fiscal note):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

Sam
he should have used the $175 million statistic, & compared it to the Interior (Bradley or something? completion?)

March 2, 1988

The Honorable Mitch Abood
Chairman
Committee on State Affairs
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Mr. Chairman:

I am writing to request an early hearing on CSHB 164(Fin) amended, the so-called "ELF" bill.

In July of last year the economic limit factor (ELF) began reducing production taxes in the Prudhoe Bay field. This came as no surprise; administration officials testified to this last year in the House. Since then, however, new information has become available suggesting that the ELF factor is creating an incentive for operators to drill additional wells, and that as a result the revenue losses resulting from the ELF will be substantially larger than anticipated. Moreover, according to other recent indications, the current ELF may be creating an unexpectedly large obstacle to the development of some small and marginal fields.

These new developments obviously have important ramifications for the state's fiscal condition, for our management of the state's oil resources, and for the consideration of CSHB 164. My administration looks forward to an early opportunity to present testimony on these critical matters before your committee.

Sincerely,

Steve Cowper
Governor

FISCAL EFFECTS OF ELF ALTERNATIVES

Additional Revenue (Millions) At the 30th percentile

	FY 87-88	FY 89	FY 90	FY 91	FY 92
HB-164	*76.7*	*92.0*	*98.5*	*99.9*	*105.6*
Proposed CSHB-164 (Res.)*	*98.6*	*98.1*	*109.6*	*96.1*	*94.2*

FY93
HB-164 → Ø.
Proposed CSHB-164 (Res.)* → 90+.

*Indicates provisional OMB estimate pending DOR fiscal analysis due next week.

I want to see 15-yr. projections

ESTIMATED SEVERANCE TAX RATES*

	Prudhoe Bay	Kuparuk River	Milne Point	Endicott	Lisburne	McArthur River	Granite Point
Current Law	12.6%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
HB-164	15.0%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
Proposed CSHB-164 (Res.)	14.8%	10.7%	0.3%	0.3%	3.6%	0.0%	0.0%

*North Slope values are forecast FY 88 averages; Cook Inlet values are estimated Dec 1986 rates; Cook Inlet fields not listed have zero effective rates under all alternatives.

OMB, Division of Policy, 3/18/87

A M J

Sam revised ELF fiscal note

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

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Publish Date:

REQUEST

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MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
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FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: Attach a separate page if necessary

This bill would change the Economic Limit Factor (ELF) to introduce field size as a consideration in establishing the effective severance tax rate on oil production. Fields producing in excess of roughly 120,000 barrels per day will have a higher rate than currently calculated. Other fields will have a lower rate.

Prepared By: Charles L. Logsdon (Vincent Knight for)
Phone: 276-3364
Division: Commissioner's Office
Date: April 20, 1987

Approved by Commissioner: Hugh Malone
Date: April 21, 1987
Agency: Department of Revenue

Distribution (by Agency preparing fiscal note):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)
Senate Secretary

MEMORANDUM

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

April 14, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist CL

Subject: CSHB164

We have recently made another run of the Petrev model to prepare estimates of the fiscal impact of CSHB164 passed by the House of Representatives. The only change made in this legislation not examined in prior fiscal notes was allowing either the taxpayer or the department to rebut the 300 barrels per well day presumed production at the economic limit (PEL). The fiscal note we prepared for the original CSHB164 fixed the PEL at 300 barrels per well day.

The fiscal impact of the final version is almost exactly the same as with the PEL fixed at 300 (Table 1). As might be expected, the lower PEL (department rebuts) dominates the higher PEL (comany rebuts)in both the 30% or downside risk case and the mean except for the near term when very low prices are a distinct possibility. That is, we would expect severance taxes to be higher the higher the price of oil because the PEL would be lower and consequently the ELF would be higher. In general however it turns out that given our assumptions about the probabilty distribution of oil prices, the higher PELs and lower PELs tend to offset each other with the result that the final outcome at both the Mean and 30% levels is not that much different than if the PEL were fixed at 300.

The revenue and production effects of the final version of CSHB164 as well as a comparison of effective tax rates by field for current law and CSHB164 are found in the following tables.

Table 1
The Effect on Fiscal Impact of CSHB164
With and Without PEL Fixed at 300
(Million $)

Fiscal Year	PEL Variable 30%	PEL=300 Fixed 30%	Impact Variable 30%	PEL Variable Mean	PEL=300 Fixed Mean	Impact Variable Mean
1988	88.14	88.69	-.55	108.21	109.41	-1.2
1989	108.04	108.49	-.45	129.96	129.93	.03
1990	118	117.56	.44	142.09	140.61	1.48
1991	115.76	112.39	2.37	143.3	140.23	3.07
1992	123.17	117.76	5.41	144.3	139.63	4.68
1993	134.65	129.08	5.57	147.22	138.85	8.38
1994	118.62	110.41	8.21	140.17	131.58	8.59
1995	113.31	102.41	10.9	136.02	128.49	7.53
1996	110	97.7	12.3	133.88	123.89	9.99
1997	112.94	100.35	12.49	136.74	122.39	14.35
1998	102.16	88.16	14	136.93	121.19	15.74
1999	104.76	90.94	13.82	134.24	119.36	14.88
2000	83.06	69.02	14.04	140.05	123.15	16.9
2001	75.71	62.84	12.87	141.23	123.61	17.62
2002	68.01	59.11	8.9	139.01	121.55	17.46
2003	59.48	50.11	9.37	137.31	118.3	19.01
2004	41.69	30.51	11.18	129.49	108.62	20.87
2005	29.03	21.14	7.89	102.3	88.98	13.32

Table 2
Comparison of the March 1987 DOR Petroleum Production
Revenue Forecast and CSHB164
(Million $)

Fiscal Year	March Official 30%	CSHB164 30%	March Official Mean	CSHB164 Mean	Delta 30%	Delta Mean
1987	1108.87	1114.39	1162.46	1168.36	5.52	5.9
1988	1139.59	1277.73	1437.59	1545.8	88.14	108.21
1989	1319.14	1427.13	1630.02	1759.88	108.04	123.96
1990	1441.42	1559.42	1760.32	1905.31	118	142.09
1991	1330.42	1446.13	1656.31	1800.41	115.76	143.6
1992	1431.66	1554.83	1803.98	1959.48	123.17	144.5
1993	1503.92	1638.57	1937.47	2084.7	134.65	147.23
1994	1550.06	1668.68	2239.29	2429.46	118.62	140.17
1995	1512.66	1625.97	2368.06	2504.08	113.31	136.02
1996	1470.59	1580.59	2329.13	2463.01	110	133.88
1997	1455.73	1568.57	2695.79	2832.53	112.84	136.74
1998	1424.09	1526.25	2658.19	2795.12	102.16	136.93
1999	1366.82	1471.58	2594.32	2728.56	104.76	134.24
2000	1312.73	1395.79	2541.24	2681.29	83.06	140.05
2001	1269.4	1345.11	2489.63	2630.86	75.71	141.23
2002	1223.23	1291.24	2454.13	2593.14	68.01	139.01
2003	1198.75	1258.23	2537.33	2674.64	59.48	137.31
2004	1174.99	1216.68	2516.98	2646.47	41.69	129.49
2005	1161.32	1190.35	2486.44	2588.74	29.03	102.3

Table 3
Production Impact of CSHB164
(Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1988	0	0	.28	0	0	0	0	0	.28
1989	0	0	.3	0	0	0	0	0	.3
1990	0	0	.28	0	0	0	0	0	.28
1991	0	0	.24	0	0	0	0	0	.24
1992	0	0	.21	.03	0	0	.46	0	.7
1993	0	0	.21	.03	0	0	.83	0	1.07
1994	-1.47	-.05	.2	.02	-.79	0	.87	0	-1.22
1995	-1.29	-.04	.44	.07	-.7	-.84	.8	0	-1.56
1996	-1.13	-.03	.46	.07	-.62	-.97	.81	0	-1.41
1997	-2.47	-.02	.46	.05	-.55	-1.21	.86	0	-2.88
1998	-2.17	-.02	.38	.04	-.49	-1.07	.79	.27	-2.27
1999	-1.9	-.02	.29	.04	-.43	-1.18	.53	.39	-2.28
2000	-1.67	-.01	.19	.02	-.38	-1.17	.29	.38	-2.35
2001	-1.46	0	.15	.01	-.35	-.96	.14	.39	-2.08
2002	-1.37	0	-.01	.01	-.31	-1.09	.09	.5	-2.18
2003	-1.13	.01	-.09	-.01	-.27	-.76	-.02	.55	-1.72
2004	-1.16	0	-.11	0	-.24	-1.13	-.12	.5	-2.26
2005	-1.12	-.02	-.07	0	-.22	-.66	-.19	.49	-1.78
									0
									0
Total	-18.34	-.2	3.82	.36	-5.35	-11.03	6.14	3.47	-21.11

Table 4
Increase (Decrease) in Average Severance Tax Rate With CSHB164

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore
1988	.0216	.0361	-.0480	-.0590	-.0585	0	0	0
1989	.0209	.0358	-.0438	-.0043	-.0266	0	0	0
1990	.0219	.0357	-.0360	-.0038	-.0118	0	0	0
1991	.0240	.0344	-.0513	-.0038	-.0009	0	0	0
1992	.0236	.0325	-.0544	-.0037	.0024	0	0	0
1993	.0235	.0295	-.0555	-.0044	.0107	0	-.0518	0
1994	.0215	.0255	-.0544	-.0146	.0146	0	-.0533	0
1995	.0219	.0219	-.0551	-.0200	.0143	.0037	-.0522	0
1996	.0231	.0163	-.0564	-.0277	.0141	.0116	-.0501	0
1997	.0223	.0111	-.0571	-.0306	.0138	.0157	-.0481	0
1998	.0235	.0043	-.0563	-.0281	.0136	.0162	-.0541	0
1999	.0246	-.0015	-.0532	-.0200	.0120	.0171	-.0506	-.0836
2000	.0256	-.0070	-.0507	-.0113	.0104	.0192	-.0546	-.0747
2001	.0252	-.0103	-.0422	-.0041	.0086	.0227	-.0509	-.0724
2002	.0247	-.0076	-.0280	-.0017	.0056	.0210	-.0501	-.0743
2003	.0239	-.0040	-.0251	-.0007	.0001	.0221	-.0546	-.0792
2004	.0231	-.0001	-.0453	-.0007	-.0034	.0213	-.0521	-.0911
2005	.0219	0	-.0505	-.0114	-.0073	.0036	-.0484	-.0960

Sam -
good tables at
the back on %
of income

STATE OF ALASKA
DEPARTMENT OF REVENUE
OFFICE OF THE COMMISSIONER

M E M O R A N D U M

TO: Vince Wright
Chief of Research

FROM: John Larson
Economist

DATE: March 23, 1987

SUBJECT: Standard Alaska Petroleum
Corporations's HB 164 Analysis

Standard Alaska Petroleum Corporation has developed an analysis which indicates the percentage of petroleum production net income, from all Alaskan producing fields (North Slope and Cook Inlet), which the state would collect from petroleum production revenues, over the period from FY 1988 through FY 1992, both under current law and under HB 164. The FY 1988 through FY 1992 period was chosen because HB 164 would extend the rule, setting the Petroleum Production Tax ELF equal to 1 if it is greater than .7 for the first 10 years of production from a field, to the first 15 years of production. Sadlerochit is the only field for which the ELF is greater than .7 and the proposed 15 year rule would apply to Sadlerochit through 1992. Thus HB 164 would only impact Sadlerochit and only for the FY 1988 through FY 1992 period. Standard's analysis was derived directly from $9 per barrel wellhead value scenario in the HB 353 Sensitivity Analysis which was published by the Department of Revenue in December 1986. The analysis shows that the state would collect 96 percent of production net income under current law and 102 percent of production net income under HB 164 over the period in question.

While the information in Standard's analysis is consistent with the information presented in the Department of Revenue's HB 353 Analysis, it may be somewhat misleading for the following reasons:

1) The idea of analysing the percentage of income from petroleum production activities within Alaska which the state collects from petroleum production revenues may be useful. However, the issue of how to define the total income or benefit resulting from production activities needs to be considered. The way in which Standard has structured its analysis assumes the benefits or income from oil production end at the wellhead. This would be a valid approach if the Alaska North

Slope (ANS) producers were only producing Alaskan oil and selling it through "arms length" transactions on the world market. However, the real situation is that the ANS producers are also involved in transportation, refining and marketing of ANS crude within their own integrated business. Therefore to arbitrarily limit the net income percentage share analysis to the wellhead may significantly understate the income which ANS producers actually derive from ANS production. Even the inclusion of TAPS income, ANS producers also own TAPS, in the analysis would not present a complete picture of the economics of ANS production for the producers.

2) The concept of net income which is used in the Standard analysis is valid for taxation purposes but has little meaning in the economic analysis. The calculation of net income from a taxation standpoint allows the deduction of depreciation and amortization. While depreciation and amortization do represent legitimate tax deductions, they also represent a cash flow benefit to the producers. Investment and operating decisions are based on net cashflow not net income. State production revenues would be a significantly smaller percentage of production net cashflow than of production net income. This point, along with the points raised in 1) above explain why the producers are still operating and making production capital investments even though according to Standard the state is taking nearly 100 percent of net income.

3) Insofar as HB 164 is concerned, it would be more valid to look at production net income, net cashflow and state production revenues for the Sadlerochit field alone rather than for all Alaskan fields as Standard has done. This is because HB 164 only impacts Sadlerochit as discussed above. The attached Table I presents Sadlerochit production net income and net cashflow for the period from FY 1988 through FY 1992 based on the assumptions of the $9, $11 and $13 per barrel scenarios in the December 1986 HB 353 Sensitivity Analysis. The table also shows state production revenues for the period under both current law and HB 164 as a percentage of both net income and net cashflow for each of the three wellhead value scenarios. Note that state production revenues as a percentage of net income in the $9 per barrel wellhead value scenario are 65 percent under current law and 71 percent under HB 164 compared to the 96 percent and 102 percent respectively which are shown in Standard's analysis under the same scenario but using all Alaskan fields rather than just Sadlerochit. When state production revenues are analysed as a percentage of net cashflow rather than net income the percentages drop to 40 percent under current law and 43 percent under HB 164. Also, note that if higher wellhead value scenarios are considered the state production revenue percentages of both production net income and net cashflow decline. Finally it should be remembered that in this analysis of Sadlerochit, income and cashflow, are defined at the wellhead and as discussed in 1) above there are additional benefits which accrue to the producers from this production.

4) Subsequent to Standard's analysis of HB 164 a new version of ELF legislation has been introduced, CSHB 164. Like HB 164, CSHB 164 would freeze the PEL in the ELF formula at 300 barrels per well per day. However CSHB 164 would eliminate the .7 rule and introduce a 55,000,000 scaling factor into the ELF formula. Thus beginning in FY 1988 the effective ELF would be the calculated ELF using the fixed PEL of 300 and the 55,000,000 scaling factor for all fields. The effect of this change would be to increase the effective ELF and thus Petroleum Production Tax for any field with production greater than 43.6 million barrels per year (119,452 barrels per day) and to reduce the effective ELF and Petroleum Production Tax for any field with production less than 43.6 million barrels per year. Under the assumptions of the $9 per barrel WHV scenario of the December 1986 HB 353 Sensitivity Analysis, the Petroleum Production Tax, for the FY 1988 through FY 1992 period, would be increased for Sadlerochit and Kupuruk and decreased for all other North Slope fields under the provisions of CSHB 164. The total North Slope revenue impact of CSHB 164 would be $496.80 million with $427.54 million due to Sadlerochit compared to $483.14 million, all due to Sadlerochit, under HB 164. Under CSHB 164 Sadlerochit would account for over 85 percent of the total revenue increase over the period. Table II shows the impact of CSHB 164 on the Sadlerochit field under the same set of assumptions as Table I shows for HB 164.

Table I
SADLEROCHIT OIL FIELD
Analysis of State Oil Production Revenues
With & Without Enactment of HB 164
As a Percentage of
Oil Production Net Income & Net Cash Flow
Based on 12/86 HB 353 Sensitivity Analysis
Sum FY 1988 - 1992

($ = millions 1986 $)

Wellhead Value Scenario	(1) Net Income	(2) State Revenue w/o HB164	(3) Revenue As % Of Net Income	(4) Revenue Impact HB 164	(5) State Revenue w/HB164	(6) Revenue As % Of Net Income
$9	8597.02	5590.58	65.03%	483.14	6073.72	70.65%
$11	12941.92	6636.80	51.28%	590.02	7226.82	55.84%
$13	17474.99	7669.42	43.89%	697.87	8367.29	47.88%

	(7) Net Cashflow	(8) State Revenue w/oHB164	(9) Revenue As % Of Net Cash Flow	(10) Revenue Impact HB 164	(11) State Revenue w/HB 164	(12) Revenue As % Of Net CashFlow
$9	13971.28	5590.58	40.01%	483.14	6073.72	43.47%
$11	18257.29	6636.80	36.35%	590.02	7226.82	39.58%
$13	22518.88	7669.42	34.06%	697.87	8367.29	37.16%

Assumptions:

1. HB 164 extends the .7 ELF rule for Sadlerochit for 5 years from FY 1988 through FY 1992 and freezes the PEL at 300. The impact of HB 164 on state revenues is shown in columns (4) and (10).

2. Net income in column (1) is derived by deducting the following non-tax items from gross income: Operating costs, depreciation and amortization. Administration, overhead and uncapitalized interest expenses for the total North Slope are allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

3. Net cashflow in column (7) is derived by adding back depreciation and amortization to net income in column (1).

4. State oil production revenues under current law without HB 164 in columns (2) and (8) and with HB 164 in columns (5) and (11) include oil royalties, oil production taxes and oil conservation taxes. Also included is Petroleum Corporate Income Tax under the current modified apportionment law allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

Table II
SADLEROCHIT OIL FIELD
Analysis of State Oil Production Revenues
With & Without Enactment of CSHB 164
As a Percentage of
Oil Production Net Income & Net Cash Flow
Based on 12/86 HB 353 Sensitivity Analysis
Sum FY 1988 - 1992

($ = millions 1986 $)

Wellhead Value Scenario	(1) Net Income	(2) State Revenue w/oCSHB164	(3) Revenue As % Of Net Income	(4) Revenue Impact CSHB164	(5) State Revenue w/CSHB164	(6) Revenue As % Of Net Income
$9	8597.02	5590.58	65.03%	427.54	6018.12	70.00%
$11	12941.92	6636.80	51.28%	522.54	7159.34	55.32%
$13	17474.99	7669.42	43.89%	617.56	8286.98	47.42%

	(7) Net Cashflow	(8) State Revenue w/oCSHB164	(9) Revenue As % Of Net Cash Flow	(10) Revenue Impact CSHB 164	(11) State Revenue w/CSHB 164	(12) Revenue As % Of Net CashFlow
$9	13971.28	5590.58	40.01%	427.54	6018.12	43.07%
$11	18257.29	6636.80	36.35%	522.54	7159.34	39.21%
$13	22518.88	7669.42	34.06%	617.56	8286.98	36.80%

Assumptions:

1. CSHB 164 introduces a 55,000,000 scaling factor into the exponent of the current ELF formula and fixes the PEL at 300 barrels per well per day. The impact of CSHB 164 on state revenues is shown in columns (4) and (10).

2. Net income in column (1) is derived by deducting the following non-tax items from gross income: Operating costs, depreciation and amortization. Administration, overhead and uncapitalized interest expenses for the total North Slope are allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

3. Net cashflow in column (7) is derived by adding back depreciation and amortization to net income in column (1).

4. State oil production revenues under current law without CSHB 164 in columns (2) and (8) and with CSHB 164 in columns (5) and (11) include oil royalties, oil production taxes and oil conservation taxes. Also included is Petroleum Corporate Income Tax under the current modified apportionment law allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST

Bill Version: CS HB 164
Publish Date:

Pevision Date:
Title: An act relating to the oil and gas production tax.
Sponsor: Rules/Goverror
Requestor: House Resources

Agency Affected: Revenue
BRU: Audit

Components: Oil & Gas

EXPENDITURES/REVENUES: (Millions of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	-	88.7	108.5	117.6	112.9	117.8

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: The above numbers represent the increase in general fund revenues if this bill becomes law. The key assumptions are introduction of a 55,000,000 scaling factor into the exponent of the current ELF formula and fixing the value of the Production at the Economic Limit (PEL) at 300 barrels per well per day. The production impact from FY88 through FY2005 represents a cumulative total loss of 20.9 million barrels.

Prepared By: Chuck Logsdon
Division: Office of the Commissioner

Phone: 276-5364
Date: 3/19/87

Approved by Commissioner:
Agency: Revenue

Date: 3/19/87

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Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

MEMORANDUM

TO: All Members of the Alaska Legislature

FROM: Senator Mitch Abood, Chairman
Senate Committee on State Affairs

DATE: May 2, 1988

SUBJECT: CS for House Bill 164, the so-called ELF bill

As I promised last week, Elfie has gone through the "Oil Tax Quiz" that the Governor's number crunchers put out April 15th. Today Elfie is reporting on the first 3 questions from the quiz.

Elfie just can't believe how the Governor's number crunchers keep on makin' more mistakes. And Elfie is curious that IF their manipulating of the numbers is not a "deliberate attempt to deceive the public" THEN WHAT IS IT?

Elfie is also glad that "legislators and the public are not being fooled" by the Governor's number crunchers.

GOVERNOR'S NUMBER CRUNCHER ERROR VI:

Question 1 on the oil tax quiz was:

1. How much profit does the oil industry make each day from North Slope oil and the pipeline?

___ A. The industry is making no profit on the Slope.
___ B. $800,000 per day.
___ C. $2,200,000 per day.
___ D. $6,200,000 per day.

The Governor's number crunchers said the correct answer is D. The truth is that the correct answer would be "None of the above." The number crunchers cite Petroleum Intelligence Weekly for their answer to this question, but some of PIW's cost figures are incorrect.

For example, PIW's figure ($0.15 per barrel) for state and municipal property taxes works out to a total property tax of $109.5 million. But the Department of Revenue's own 1988 assessed value of the North Slope fields and pipelines is $16.95 billion. With the total tax rate at 20 mills (2%), **THE TAX FOR THESE PROPERTIES IS $339 MILLION, NOT $109 MILLION**, which makes the true property tax per barrel for 1988 **$0.46 -- NOT $0.15.**

The Governor's number crunchers also ignored the Department of Revenue's own estimate of the production costs for North Slope fields, probably because it is higher that PIW's figure. According to the Department of Revenue, production costs in 1988 are $1.61 **PER BARREL**, not the $0.85 figure from PIW.

With just these 2 corrections to the numbers, the **INDUSTRY'S PROFIT DROPS** from $3.03 per barrel to $1.92. The state and local share **GOES UP** by the $0.31 per barrel which was **LEFT OUT** of PIW's property tax figure, to a total of $2.68 per barrel or $5.4 million a day.

From this information it is also clear that the Governor's number crunchers answer to their second question is also wrong.

GOVERNOR'S NUMBER CRUNCHER ERROR VII:

Question 2 on the oil tax quiz was:

2. How do state and industry shares of North Slope oil income compare?

___ A. State and local 80%/industry 5%/ feds 15%.
___ B. State and local 60%/industry 15%/feds15%.
___ C. State and local 45%/industry 35%/feds 20%.
___ D. State and local 35%/industry 45%/feds 20%.

The Governor's number crunchers said the correct answer is D, even though it is clear that the state and local government's are making 40% more ($2.68 per barrel) than industry ($1.92 per barrel), using the corrected PIW figures. **THE DEPARTMENT OF REVENUE'S OWN ANALYSIS CONFIRMS THIS RESULT.** The Department has figured that the state and local share is 57% for this year at $15 - $16 market prices, and they have predicted that this figure will rise to 67% by 1991 (see Elfie memo of March 23).

GOVERNOR'S NUMBER CRUNCHER ERROR VIII:

Question 3 on the oil tax quiz was:

3. How many new jobs has the oil industry created on the North Slope since the ELF became effective at Prudhoe Bay in June of 1987?

___ A. 2,400 jobs.
___ B. 800 jobs.
___ C. 200 jobs.
___ D. Oil industry jobs on the Slope appear to have declined.

The Governor's number crunchers said D, ignoring the simple arithmetic that shows A is correct. There are currently 8 drilling rigs working on the North Slope. Elfie's experience shows that each rig creates 50 to 100 direct jobs, and at least another 200 indirect jobs. **THIS MEANS 250 TO 300 JOBS ARE CREATED FOR EACH RIG THAT IS WORKING. 8 RIGS MEANS 2,000 - 2,400 JOBS!!!!**

The Governor's number crunchers point to Department of Labor statistics showing that the number of jobs on the Slope was less in the 4th quarter of 1987 that in the 4th quarter of 1986. **THESE STATISTICS DON'T SAY ANYTHING ABOUT HOW MUCH MORE THE NUMBER OF JOBS WOULD HAVE DECLINED ON THE SLOPE IF THE 8 RIGS WERE IDLE.** Also, since the Commissioner of the Department of Labor has personally been dragged into the ELF debate as a "CONDUIT" by the number crunchers, Elfie is wondering whether his statistics weren't "cooked" a little bit in order to win entry into the Governor's number crunchers' inner circle.

THE NUMBER CRUNCHERS ALSO IGNORED EVIDENCE BY THE SUPPORT INDUSTRY ALLIANCE THAT THE ELF HAS BEEN CREATING NEW JOBS. Out of more that 200 members in the Alliance, 79 reported a total gain of 636 employees in the first 10 months that the ELF was back in effect for Prudhoe Bay, and they expect the total gain to be over 1,000 new jobs by the end of its first year.

THE GOVERNOR'S NUMBER CRUNCHERS SCORED A BIG, FAT ZERO FOR EACH OF THE FIRST 3 QUESTIONS. Attached are the copies from the Department of Revenue's study where Elfie found the straight facts.

The real truth hasn't changed. **ELF IS WORKING, AND WORKING WELL.** It is creating jobs for Alaskans. It is stimulating economic activity in Alaska. It is increasing recoverable oil reserves.

As has been proven over and over, the solution to Alaska's economic problems is not increasing taxes in order to fuel the big spending House Majority and Governor's proposed 16% budget increase.

The Governor's number crunchers will continue to take the **"OPPORTUNITY TO MAKE OUR CASE ON THE ELF IF AND WHEN THE OIL COMPANIES TELL THE SENATE THEY CAN LET US HAVE A PUBLIC HEARING."** Now what do you think I got the above quote from??? **BOY HOWDY, AIN'T THEY SLICK!!!!**

AND WOULD YOU BELIEVE, THERE'S MORE TO COME!!!

SENSITIVITY ANALYSIS
OF
PROJECTED REVENUE COLLECTIONS

HB 353

COMPARED TO

CURRENT LAW

ALASKA DEPARTMENT OF REVENUE
DECEMBER 1986
By
John Larson, Economist
Charles Logsdon, Petroleum Economist
Roger Marks, Petroleum Economist

TABLE II-11-1
ALL NORTH SLOPE PRODUCING FIELDS SEPARATE ACCT (HB333) INCOME TAX ESTS
10-1986 #1 SENSITIVITY ANALYSIS $11/B WHV

FISCAL YEAR	PROD VOL WT AVG GROSS WELLHEAD VALUE $/B	TOTAL GROSS PRODN VOL MMB/Y	TOTAL GROSS REV MM$/Y	ROYALTY SHARE MM$/Y	PRODN & CONS TAX MM$/Y	PPTY TAX MM$/Y	OPER COSTS MM$/Y	DEPREC EXPENSE MM$/Y	AMORT EXPENSE MM$/Y	UNCAP INTEREST EXPENSE ALLOWED MM$/Y	ADMIN & OVERHD EXPENSE ALLOWED MM$/Y
1986	10.81650	831.00	7041.50	855.84	810.65	314.01	1137.47	1327.00	0.51	105.00	240.00
1987	10.78010	661.00	7131.19	852.99	781.34	236.69	1157.10	1555.63	30.29	105.00	240.00
1988	10.72040	637.00	6833.99	876.68	559.18	254.74	1172.17	1180.40	16.05	105.06	240.00
1989	10.61610	637.00	6761.10	810.65	542.03	256.44	1191.09	1816.22	72.11	105.00	240.00
1990	10.59110	602.00	6376.19	772.74	502.70	246.42	1155.66	1800.97	77.96	105.00	240.00
1991	10.57760	545.00	5766.79	699.94	442.10	212.74	1089.69	1752.63	77.06	105.00	240.00
1992	10.57127	490.00	5179.92	629.30	385.69	238.43	1020.67	1025.70	75.02	105.00	240.00
1993	10.56500	442.00	4661.05	595.30	361.04	217.55	1095.20	1966.70	74.59	105.00	240.00
1994	10.41152	421.00	4467.05	541.02	324.49	241.00	1050.06	1957.44	69.51	105.00	240.00
1995	10.40016	383.00	4010.14	492.31	294.28	230.07	1037.32	1811.77	61.99	105.00	240.00
1996	10.40070	340.00	3506.27	432.45	253.90	211.23	957.04	1631.93	53.63	105.00	240.00
1997	10.40593	300.00	3161.70	381.32	219.56	192.39	810.30	1423.46	44.46	105.00	240.00
1998	10.62517	268.00	2847.66	348.56	194.73	173.55	825.19	1259.39	37.29	105.00	240.00
1999	10.62814	242.00	2570.60	307.37	173.70	155.39	784.75	1111.56	32.69	105.00	240.00
2000	10.61156	208.00	2207.20	264.86	143.28	137.23	746.41	970.70	20.07	105.00	240.00
2001	10.81807	183.90	1988.08	234.65	134.95	119.06	645.45	730.37	13.95	105.00	240.00
2002	10.88727	165.00	1789.80	211.13	122.39	103.02	619.17	659.25	11.96	105.00	240.00
2003	10.95040	136.00	1475.40	171.19	103.74	88.58	544.52	493.45	0.10	105.00	240.00
2004	11.00000	107.00	1177.00	137.76	90.32	75.60	442.97	350.91	0.01	105.00	240.00
2005	11.00000	93.00	1023.00	122.31	79.88	66.15	431.62	311.56	0.00	105.00	240.00

FISCAL YEAR	EXPLOR (UNSUCCESS) EXPENSE ALLOWED MM$/Y	TOTAL DEDUCT MM$/Y	TOTAL TAXABLE INCOME MM$/Y	TOTAL TAX LIAB MM$/Y	WINDFALL PROFITS TAX MM$/Y	TOTAL DEDUCT W/WPT MM$/Y	TOTAL TAXABLE INCOME W/WPT MM$/Y	TOTAL TAX LIAB W/WPT MM$/Y	PRODN TAX CURRENT MM$/Y	PRODN TAX HB333 MM$/Y
1986	176.00	4926.16	2115.38	198.05	0.00	4926.16	2115.38	198.05	859.94	859.94
1987	176.00	5125.04	2006.15	180.58	0.00	5125.04	2006.15	180.58	863.90	780.61
1988	176.00	5056.52	1777.47	167.08	0.00	5056.52	1777.47	167.08	679.71	550.79
1989	176.00	5247.30	1513.01	142.30	0.00	5247.30	1513.01	142.39	655.50	511.74
1990	176.00	5077.25	1298.94	122.10	0.00	5077.25	1298.94	122.10	603.92	502.05
1991	176.00	4016.26	948.53	89.16	0.00	4016.26	948.53	89.16	537.10	441.79
1992	176.00	4690.70	480.13	45.13	0.00	4690.70	480.13	45.13	487.75	385.85
1993	176.00	4859.55	21.40	2.02	0.00	4859.55	21.48	2.02	441.10	360.50
1994	176.00	4715.04	-247.59	-23.27	0.00	4715.04	-247.59	-23.27	396.77	324.05
1995	176.00	4481.96	-421.80	-39.65	0.00	4481.96	-421.80	-39.65	359.03	293.07
1996	176.00	4041.09	-457.62	-43.02	0.00	4041.09	-457.62	-43.02	310.35	253.61
1997	176.00	3674.98	-493.20	-46.36	0.00	3674.98	-493.20	-46.36	260.45	219.23
1998	176.00	3351.71	-504.11	-47.39	0.00	3351.71	-504.11	-47.39	238.08	194.43
1999	176.00	3100.46	-537.66	-50.56	0.00	3100.46	-537.66	-50.56	212.37	173.46
2000	176.00	2818.63	-611.43	-57.47	0.00	2818.63	-611.43	-57.47	175.08	142.98
2001	176.03	2407.78	-424.78	-39.93	0.00	2407.78	-424.78	-39.93	164.99	134.75
2002	176.00	2210.72	-450.92	-43.14	0.00	2210.72	-450.92	-43.14	149.64	122.21
2003	176.00	1926.65	-451.65	-42.40	0.00	1926.65	-451.05	-42.40	134.08	103.59
2004	176.00	1618.65	-441.65	-41.52	0.00	1618.65	-441.65	-41.52	110.65	90.20
2005	176.00	1552.60	-487.60	-45.83	0.00	1552.60	-487.60	-45.83	97.69	79.78

TABLE 11-11-8
PERCENTAGE SHARE COMPARISON
CALCULATION OF STATE PETROLEUM PRODUCTION REVENUES
AS A PERCENTAGE OF
PETROLEUM PRODUCTION NET INCOME
11-11986(?)   SENSITIVITY ANALYSIS 111/B MIV

FISCAL YEAR	TOTAL PETRO PRODN GROSS INCOME MM$/Y	TOTAL PETRO PRODN NON TAX DEDUCTS MM$/Y	TOTAL PETRO PRODN NET INCOME MM$/Y	CURRENT LAW STATE PETRO PRODN REVENUE MM$/Y	CURRENT LAW REVENUE VS NET INCOME %	GROSS STATE PETRO PRODN REVENUE MM$/Y	REVENUE VS NET INCOME %
1986	7500.88	3356.16	4144.73	2202.26	53.13	2215.11	53.44
1987	7557.00	3635.95	3921.09	2190.41	55.86	2119.93	54.37
1988	7277.88	3805.89	3471.99	1895.12	52.46	1890.47	54.45
1989	7207.41	4014.41	3192.72	1966.22	61.58	1849.82	57.94
1990	6870.36	3939.66	2930.70	1848.60	63.58	1746.29	59.42
1991	6362.27	3825.44	2536.83	1726.83	67.54	1533.36	62.44
1992	5855.26	3830.44	2024.82	1591.75	78.49	1449.40	71.59
1993	5599.09	4041.84	1557.25	1540.69	98.98	1366.06	87.72
1994	5333.36	3991.10	1342.18	1459.76	108.74	1296.98	96.61
1995	5130.65	3831.28	1287.41	1390.25	107.98	1256.29	97.57
1996	4675.18	3516.27	1159.21	1256.94	108.43	1145.32	98.80
1997	4214.31	3233.76	1010.12	1100.73	109.46	1016.24	100.56
1998	3961.08	2994.92	966.16	1018.41	108.58	967.81	100.17
1999	3671.09	2824.05	847.04	961.00	113.58	892.58	105.28
2000	3285.88	2610.13	675.75	853.46	126.30	795.34	117.76
2001	3016.17	2239.58	776.68	779.67	100.37	728.45	93.80
2002	2833.67	2131.31	702.16	721.85	102.76	670.60	95.61
2003	2482.14	1880.97	601.13	631.62	105.37	597.83	99.45
2004	2160.58	1634.80	525.78	557.56	106.05	529.50	100.72
2005	2016.21	1594.89	431.92	512.51	110.66	490.51	113.57

MEMORANDUM

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

April 14, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist CL

Subject: CSHB164

We have recently made another run of the Petrev model to prepare estimates of the fiscal impact of CSHB164 passed by the House of Representatives. The only change made in this legislation not examined in prior fiscal notes was allowing either the taxpayer or the department to rebut the 300 barrels per well day presumed production at the economic limit (PEL). The fiscal note we prepared for the original CSHB164 fixed the PEL at 300 barrels per well day.

The fiscal impact of the final version is almost exactly the same as with the PEL fixed at 300 (Table 1). As might be expected, the lower PEL (department rebuts) dominates the higher PEL (comany rebuts)in both the 30% or downside risk case and the mean except for the near term when very low prices are a distinct possibility. That is, we would expect severance taxes to be higher the higher the price of oil because the PEL would be lower and consequently the ELF would be higher. In general however it turns out that given our assumptions about the probabilty distribution of oil prices, the higher PELs and lower PELs tend to offset each other with the result that the final outcome at both the Mean and 30% levels is not that much different than if the PEL were fixed at 300.

The revenue and production effects of the final version of CSHB164 as well as a comparison of effective tax rates by field for current law and CSHB164 are found in the following tables.

Table 1
The Effect on Fiscal Impact of CSHB164
With and Without PEL Fixed at 300
(Million $)

Fiscal Year	PEL Variable 30%	PEL=300 Fixed 30%	Impact Variable 30%	PEL Variable Mean	PEL=300 Fixed Mean	Impact Variable Mean
1988	88.14	88.69	-.55	108.21	109.41	-1.2
1989	108.04	108.49	-.45	128.96	128.93	.03
1990	118	117.56	.44	142.09	140.51	1.58
1991	115.76	112.89	2.87	143.6	140.53	3.07
1992	123.17	117.76	5.41	144.5	139.65	4.85
1993	134.65	129.08	5.57	147.23	138.85	8.38
1994	118.62	110.41	8.21	140.17	131.58	8.59
1995	113.31	102.41	10.9	136.02	128.49	7.53
1996	110	97.7	12.3	133.88	123.89	9.99
1997	112.84	100.35	12.49	136.74	122.39	14.35
1998	102.16	88.16	14	136.93	121.19	15.74
1999	104.76	90.94	13.82	134.24	119.36	14.88
2000	83.06	69.02	14.04	140.05	123.15	16.9
2001	75.71	62.84	12.87	141.23	123.61	17.62
2002	68.01	59.11	8.9	139.01	121.55	17.46
2003	59.48	50.11	9.37	137.31	118.3	19.01
2004	41.69	30.51	11.18	129.49	108.62	20.87
2005	29.03	21.14	7.89	102.3	83.98	18.32

Table 2
Comparison of the March 1987 DOR Petroleum Production
Revenue Forecast and CSHB164
(Million $)

Fiscal Year	March Official 30%	CSHB164 30%	March Official Mean	CSHB164 Mean	Delta 30%	Delta Mean
1987	1108.87	1114.39	1162.46	1168.36	5.52	5.9
1988	1189.59	1277.73	1437.59	1545.8	88.14	108.21
1989	1319.14	1427.18	1630.92	1759.88	108.04	128.96
1990	1441.42	1559.42	1753.22	1895.31	118	142.09
1991	1330.42	1446.18	1656.81	1800.41	115.76	143.6
1992	1431.66	1554.83	1808.98	1953.48	123.17	144.5
1993	1503.92	1638.57	1937.47	2084.7	134.65	147.23
1994	1550.06	1668.68	2289.29	2429.46	118.62	140.17
1995	1512.66	1625.97	2368.06	2504.08	113.31	136.02
1996	1470.59	1580.59	2329.13	2463.01	110	133.88
1997	1455.73	1568.57	2695.79	2832.53	112.84	136.74
1998	1424.09	1526.25	2658.19	2795.12	102.16	136.93
1999	1366.82	1471.58	2594.32	2728.56	104.76	134.24
2000	1312.73	1395.79	2541.24	2681.29	83.06	140.05
2001	1269.4	1345.11	2489.63	2630.86	75.71	141.23
2002	1223.23	1291.24	2454.13	2593.14	68.01	139.01
2003	1198.75	1258.23	2537.33	2674.64	59.48	137.31
2004	1174.99	1216.68	2516.98	2646.47	41.69	129.49
2005	1161.32	1190.35	2486.44	2588.74	29.03	102.3

Table 3
Production Impact of CSHB164
(Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1988	0	0	.28	0	0	0	0	0	.28
1989	0	0	.3	0	0	0	0	0	.3
1990	0	0	.28	0	0	0	0	0	.28
1991	0	0	.24	0	0	0	0	0	.24
1992	0	0	.21	.03	0	0	.46	0	.7
1993	0	0	.21	.03	0	0	.83	0	1.07
1994	-1.47	-.05	.2	.02	-.79	0	.87	0	-1.22
1995	-1.29	-.04	.44	.07	-.7	-.84	.8	0	-1.56
1996	-1.13	-.03	.46	.07	-.62	-.97	.81	0	-1.41
1997	-2.47	-.02	.46	.05	-.55	-1.21	.86	0	-2.88
1998	-2.17	-.02	.38	.04	-.49	-1.07	.79	.27	-2.27
1999	-1.9	-.02	.29	.04	-.43	-1.18	.53	.39	-2.23
2000	-1.67	-.01	.19	.02	-.38	-1.17	.29	.38	-2.35
2001	-1.46	0	.15	.01	-.35	-.96	.14	.39	-2.08
2002	-1.37	0	-.01	.01	-.31	-1.09	.09	.5	-2.18
2003	-1.13	.01	-.09	-.01	-.27	-.76	-.02	.55	-1.72
2004	-1.16	0	-.11	0	-.24	-1.13	-.12	.5	-2.26
2005	-1.12	-.02	-.07	0	-.22	-.65	-.19	.49	-1.78
									0
									0
Total	-18.34	-.2	3.82	.38	-5.35	-11.03	6.14	3.47	-21.11

Table 4
Increase (Decrease) in Average Severance Tax Rate With CSHB164

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore
1988	.0216	.0361	-.0480	-.0590	-.0585	0	0	0
1989	.0209	.0358	-.0438	-.0043	-.0266	0	0	0
1990	.0219	.0357	-.0360	-.0038	-.0118	0	0	0
1991	.0240	.0344	-.0513	-.0038	-.0009	0	0	0
1992	.0236	.0325	-.0544	-.0037	.0024	0	0	0
1993	.0235	.0295	-.0555	-.0044	.0107	0	-.0518	0
1994	.0215	.0255	-.0544	-.0146	.0146	0	-.0533	0
1995	.0219	.0219	-.0551	-.0200	.0143	.0037	-.0522	0
1996	.0231	.0163	-.0564	-.0277	.0141	.0116	-.0501	0
1997	.0223	.0111	-.0571	-.0306	.0138	.0157	-.0481	0
1998	.0235	.0043	-.0563	-.0281	.0136	.0162	-.0541	0
1999	.0246	-.0015	-.0532	-.0200	.0120	.0171	-.0506	-.0836
2000	.0256	-.0070	-.0507	-.0113	.0104	.0192	-.0546	-.0747
2001	.0252	-.0103	-.0422	-.0041	.0086	.0227	-.0509	-.0724
2002	.0247	-.0076	-.0280	-.0017	.0056	.0210	-.0501	-.0743
2003	.0239	-.0040	-.0251	-.0007	.0001	.0221	-.0546	-.0792
2004	.0231	-.0001	-.0453	-.0007	-.0034	.0213	-.0521	-.0911
2005	.0219	0	-.0505	-.0114	-.0073	.0036	-.0484	-.0960

MEMORANDUM

State of Alaska
Department of Law

TO: Mary Halloran
Director
Division of Policy
Office of Management and Budget
Office of the Governor

DATE: March 28, 1988

FILE NO.: 663-88-0432

TEL. NO.: 465-3600

SUBJECT: Retroactivity of HB 164

FROM: Richard D. Monkman
Assistant Attorney General

You requested our opinion as to whether CSHB 164(Fin) am ("HB 164"), which would retroactively apply changes to the economic limit factor in the Oil and Gas Properties Production Tax (AS 43.55), would be likely to be held constitutionally permissible. If not, you ask our advice on "the maximum degree of retroactive application that would likely be held permissible."

The short answer is that the sections which would make HB 164 retroactive to June 1, 1987, would probably be held constitutional. If the law was retroactive to January 1, 1988, it would certainly be held constitutional.

1. Article II. The first step in analysis is the Alaska Constitution, article II, section 18:

> Laws passed by the legislature become effective ninety days after enactment. The legislature may, by concurrence of two-thirds of the membership of each house, provide for another effective date.

This section was designed to give the public three months notice of a new law before it is applied to them - unless the legislature, by a two-thirds vote, provides otherwise. State v. A.L.I.V.E. Voluntary, 606 P.2d 769 (Alaska 1980). In line with this provision, the general state policy is against retroactive statutes, based on the philosophy that people "should be able to rely on existing laws with reasonable certainty." Norton v. State, ABC Board, 695 P.2d 1090, 1093 (Alaska 1985). Retroactive application of new laws requires an express statement in the statute itself:

> No statute is retrospective unless expressly declared therein.

AS 01.10.090.

The leading case on point is Atlantic Richfield v. State, 705 P.2d 418, 438 (Alaska 1985). In this challenge to Alaska's former "separate accounting" oil tax statute, the Supreme Court upheld retroactive application of the statute back from the date of enactment to the beginning of the calendar year. The bill in question was signed into law on July 8, 1978. It provided:

> * Sec. 4. This Act applies to taxable income earned or received after December 31, 1977.
>
> * Sec. 5. The Act takes effect immediately in accordance with AS 01.10.070(c).

Ch. 110 SLA 1978.

Retroactive application was challenged by the oil companies. The Supreme Court held that the statute was "properly retroactive to January 1, 1978," because (1) the statute expressly stated it was to be retroactive, in accord with AS 01.10.090 and (2) the two-thirds vote requirement on the immediate effective date clause was met. The Court rejected oil company arguments that a separate two-thirds vote was required for retroactivity:

> AS 01.10.090 states that "[n]o statute is retrospective unless expressly declared therein." A two-thirds vote requirement does not appear in that section, or elsewhere in Alaska law. The legislature, however, has recognized that where retroactive application of a portion or all of a bill is desired, an immediate effective date, which does require a two-thirds vote under article II, sec. 18 and AS 01.10.070(a), should be used in conjunction with the retroactivity section.

705 P.2d at 438, citing Legislative Affairs Agency, Manual of Legislative Drafting 11 (1977 ed.) and Uniform Rules of the Alaska State Legislature, Rule 10 (May 3, 1977); accord, Legislative Affairs Agency, Manual of Legislative Drafting 28-29 (1987 ed.).

The language of sections 3 and 4 of HB 164 is similar to the language approved by the Supreme Court in Atlantic Richfield. Ch. 110 SLA 1978. If passed by the legislature with the requisite two-thirds vote on the effective date clause, the bill is certain to pass this first constitutional hurdle. Without passage of the effective date clause by a two-thirds vote, the retroactive application section will be void, and the bill will operate prospectively only.

2. Due Process. The next constitutional question is whether the bill would offend guarantees of due process of law. Generally speaking, there is no vested right in any particular rate of taxation. Cohan v. Commissioner, 39 F.2d 540, 545 (2d Cir. 1930) (Learned Hand, J.). Both Congress and state legislatures can change tax statutes and apply the changes retroactively:

> Taxation is neither a penalty imposed on the taxpayer nor a liability which he assumes by contract. It is but a way of apportioning the cost of government among those who in some measure are privileged to enjoy its benefits and must bear its burdens. Since no citizen enjoys immunity from that burden, its retroactive imposition does not necessarily infringe due process, and to challenge the present tax it is not enough to point out that the taxable event, the receipt of income, antedated the statute.

Welch v. Henry, 305 U.S. 134, 146-147 (1935).

The federal rule on retroactivity is that "the application of an income tax statute to the entire calendar year in which enactment took place does not per se violate the Due Process Clause of the Fifth Amendment." United States v. Darusmont, 449 U.S. 292, 297 (1980). A tax rate "may be retroactively changed at the will of Congress at least for periods of less than twelve months; Congress has done so from the outset..." Cohan, 39 F.2d at 545, quoted in Darusmont, 449 U.S. at 298. The rule is based in large part on Congressional history:

> For more than seventy-five years it has been the familiar legislative practice of Congress in the enactment of revenue laws to tax retroactively income or profits received during the year of the session in which the taxing statute is enacted, and in some instances during the year of the preceding session.

Welch, 305 U.S. at 148.

The reason behind the federal rule seems to be based on questions of "fair notice", whether "the nature or amount of the tax could not have reasonably been anticipated by the taxpayer at the time of the particular voluntary act which the statute later made the taxable event." Walsh, 305 U.S. at 147. Changes to tax rates are presumed to be foreseeable. In Darusmont, for example, the Court flatly rejected a taxpayer's argument that ret-

roactivity of an income tax change was barred by due process concerns. The Court stated that the proposed rate increase had been under public discussion in the form of bills before Congress for about a year, and therefore, the taxpayer "had ample advance notice of the increase." 449 U.S. at 299. */

State courts generally follow the federal rule, noting that "[t]ax provisions, as key components in a system designed to fairly apportion the costs of government, seldom remain static. Rather, we expect them to change in response to changing conditions." Martin v. Board of Assessment Appeals, 707 P.2d 348, 354 (Colo. 1985). The Alaska Supreme Court, as noted above, approved retroactive application of the Oil Tax Act to the full year in which it was enacted. Atlantic Richfield. In another case, the Alaska court had "no doubt" that a license fee increase could have been retroactive to the start of the year of enactment, if the legislature had followed AS 01.10.090 and "stated expressly that it intended the revised fee schedule to be retroactive." State, ABC Board v. Odom, 671 P.2d 375, 377 (Alaska 1983), quoting United States v. Hudson, 299 U.S. 498, 500 (1937) ("it has been the practice of Congress to make [income tax statutes] retroactive for relatively short periods ... and repeated decisions of this court have recognized the practice and sustained it as consistent with the due process clause of the Constitution.").

Because HB 164, as written, goes back beyond the start of the calendar year in which it will be passed, we cannot absolutely assure you that the retroactivity section will be held constitutional. By contrast, there is "no doubt" that the bill could be retroactive to January 1, 1988. Odom, Atlantic Richfield. However, going back further is perhaps not an

---

*/ The Court also rejected the taxpayer's argument, based on gift tax cases, that he "could have altered his behavior to avoid the tax if it could have been anticipated by him at the time the transaction was effected." Darusmont, 449 U.S. at 299. Gift taxes seem to be the only tax area where the Court has been receptive to arguments against retroactivity. The Court has refused to consider income in the same light as the "one time transaction" of a gift. "[A] tax on the receipt of income is not comparable to a gift tax. We cannot assume that stockholders would refuse to receive corporate dividends even if they knew that their receipt would later be subjected to a new tax or an increase of an old one." Welch v. Henry, 305 U.S. at 148-149.

insurmountable problem. The logic applied by both the United States and Alaska Supreme Courts to support the "calendar year" rule seems to apply equally well to this situation. The proposed effective date of May 31, 1987 is less than twelve months prior to the presumed date HB 164 will be enacted. Twelve months is a "short period," and was implicitly approved by the United States Supreme Court in Darusmont. The bill proposes to change tax rates, an area which is presumed to be subject to legislative change on a regular basis. In this particular case, the taxpayers have been on actual notice that the tax rate might be changed since HB 164 was introduced in January, 1987. Thus, it can be argued that the May 31, 1987 effective date does not violate due process. We believe the argument to be strong, but, given the widespread adherence to the "calendar year" approach by the courts, not absolutely certain of success.

RDM:nb

HB

164

(FILE 2)

STATE OF ALASKA
THE LEGISLATURE

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Mary Van Nimwegen

Joint Mtg of H. Finance & H. Resources 3-15-87

" " " " 3-16-87

" " " " 3-17-87

" " " " 3-19-87

Washington State
84.04.120

FOUNDED 1961. Vol.XXVII No.5 February 1, 1988

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Short-Haul Sales By Saudis Key To Overseas Stockbuild

Oil markets should be very careful in drawing grand conclusions about Saudi Arabia's oil policies on the basis of its latest foray to charter ships for moving crude oil into its overseas stockpile. The fact is that Saudi Arabia is in the process of placing a large chunk of stockpile crude with several of the Aramco partners on a delivered basis, and it chartered the tankers almost entirely to replenish those supplies, according to well informed PIW sources in shipping circles. The stockpile moves say more about Riyadh's wish to retain a basic presence as a short-haul crude supplier in the Caribbean and Europe (p5) than about its long-term goals or role within Opec (PIW Jan.25,p1). PIW confirms that the Saudis have lined up five ships to move 10-million barrels of oil into overseas storage in the coming weeks, plus at least one other vessel to supply non-Aramco clients like Ashland and Marathon. In the past, the Saudis have used the Western Hemisphere stockpile for occasional spot sales, and more routinely to supply term customers on a prompt basis.

By taking nearby crude from the stockpile now, the Aramco partners get the benefit of the oil in the heart of the winter season, rather than in late March or early April when oil loaded today in Saudi Arabia would arrive at Atlantic Basin destinations. The stockpile barrels are within the overall 1.4-million b/d of crude the partners obtained from the Saudis in January, and are expected to take in February. They do not represent any extra supply. Overall Saudi output volume is still below Opec quota in the 3.8- to 4-million b/d range (excluding the Neutral Zone). This suggests Riyadh is willing to cautiously and temporarily stick with other Opec producers in sharing some of the burden of

(continued on p.4)

Alaskan Oil Profits Staying Buoyant Amid Volatile Prices

With oil markets again threatening a possible sharp drop in prices, US Alaskan production looks surprisingly well positioned to cope with a repeat of the collapse of 1986. Despite high transport costs that would appear to make Alaskan North Slope output highly vulnerable to lower prices, it is currently making good profits at $14.50-$15.50 delivered prices, and has shown it can break even at $10 a barrel. Profits also bounce back quickly as prices recover, according to a PIW analysis of Alaskan North Slope economics (see table). Producers briefly suffered losses of a few pennies a barrel in mid-1986 when the delivered price at the Gulf Coast fell to $10. But profits rebounded to an average $3.50 in 1987, and even managed to average over $1 a barrel in disastrous 1986. ANS crude — which is one-fourth of US production — realizes a healthy $2.60-$3.20 a barrel now, depending on sales destination.

Even if prices dropped below $10, very little North Slope production would be shut in, mainly because of the large amounts already invested in current output and its importance to US supply. What's more, the oil is primarily absorbed into the refining and marketing systems of producing companies, and low crude prices usually provide

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offsetting improvements in the profitability of downstream refining. Meanwhile, the long-term outlook for Alaskan North Slope crude is encouraging a continuing buildup of production capacity, in sharp contrast to plunging production in other US areas. ANS output surged over 2-million b/d in late 1987 as Alaska displaced Texas for the first time as the largest source of US crude. The North Slope is still regarded as holding the best potential for finding big new fields. But discoveries have to be large to offset growing development and operating costs, already apparent at the Kuparuk River and Endicott fields, and for enhanced recovery in super-giant Prudhoe Bay (PIW Jan.25,p10).

Since the 1986 price collapse, the economics for Alaskan North Slope crude sold on the West Coast have become relatively more profitable than the longer shipments to the Gulf and East Coasts, which used to earn almost as much. As a result, more North Slope crude is moving to the California market, with the West Coast absorbing 60% of last year's higher production versus 50% in 1985. Profits on West Coast sales are now about 65¢ a barrel higher than those to Atlantic ports, compared to a gap of 10¢ in 1985. This mainly reflects the much larger $11.66 a barrel drop in ANS prices to Gulf and East Coast destinations in the last two years compared to a drop of just under $10 on the West Coast. The bigger decline in the east is hard to explain but is probably only partly due to the highly competitive Atlantic Basin crude oil market.

THE COMPARATIVE ECONOMICS OF ALASKAN NORTH SLOPE PRODUCTION (In dollars per barrel)

	Sales To US Gulf Coast						Sales To US West Coast					
	1988	1987		1986		1985	1988	1987		1986		1985
Delivered Price	Current	2nd H	1st H	2nd H	1st H	Year	Current	2nd H	1st H	2nd H	1st H	Year
Sohio Price	$15.50	$18.45	$17.00	$12.00	$16.80	$27.00	$14.50	$17.45	$16.00	$11.00	$15.80	$25.00
Average Price(a)	15.25	16.82	16.29	12.31	15.72	26.91	14.25	15.48	15.56	10.75	14.54	24.23
Less:												
Shipping Cost	3.35	3.21	3.19	3.38	3.72	4.21	0.99	0.96	0.94	0.94	1.14	1.29
Valdez f.o.b.	11.90	13.61	13.80	8.93	12.00	22.70	13.26	14.52	14.62	9.81	13.40	22.94
Less:												
Pipeline Loss	0.05	0.10	0.05	0.05	0.05	0.10	0.05	0.10	0.05	0.05	0.05	0.10
Pipeline Tariff	3.20	3.95	3.95	4.50	4.50	6.00	3.20	3.95	3.95	4.50	4.50	6.00
Wellhead Price(b)	8.65	9.56	9.80	4.38	7.45	16.60	10.01	10.47	10.62	5.26	8.85	16.84
Less:												
Royalty(c)	1.00	1.11	1.14	0.47	0.85	1.99	1.17	1.23	1.24	0.58	1.02	2.02
Severance(d)	0.91	1.00	1.30	0.59	0.99	2.19	1.05	1.09	1.40	0.70	1.17	2.22
Property Tax	0.15	0.15	0.15	0.18	0.18	0.21	0.15	0.15	0.15	0.18	0.18	0.21
Producing Cost	0.85	0.85	0.85	0.75	0.75	0.90	0.85	0.85	0.85	0.75	0.75	0.90
Depreciation(e)	2.25	2.25	2.25	2.17	2.17	1.53	2.25	2.25	2.25	2.17	2.17	1.53
Pre-Tax Profit	3.49	4.20	4.11	0.23	2.51	9.78	4.54	4.90	4.72	0.88	3.56	9.96
Less:												
State Income Tax(f)	0.10	0.13	0.12	0.01	0.08	0.29	0.14	0.15	0.14	0.03	0.11	0.30
US Windfall Tax(g)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
US Income Tax(h)	1.19	1.43	1.40	0.11	1.16	4.50	1.54	1.67	1.61	0.41	1.64	4.58
Oil Profit	2.29	2.64	2.59	0.12	1.28	4.99	2.86	3.09	2.98	0.45	1.81	5.08
Pipeline Profit	0.43	0.53	0.53	0.64	0.64	2.18	0.43	0.53	0.53	0.64	0.64	2.18
Overall Profit	2.63	3.17	3.12	0.76	1.92	7.17	3.29	3.62	3.51	1.09	2.45	7.26

a) Average of all producers. b) Price at Pump Station #1. c) Royalty 12.5% after deduction of gathering costs (63¢ 1988, 66¢ 1987 & 1986, 65¢ 1985). d) Severance Tax based on wellhead price after deduction of royalty (11.94% from 2nd Half 1987 to present, 14.96% 1985 to 1st Half 1987. e) Includes depletion. f) Average state income tax rate of 3% for all producers. g) Windfall profits tax not applicable at lower wellhead prices. h) US income tax rate 34% 1987 to present and 46% previously, after deduction of costs, state taxes.

Another big change in the last few years is the more even split between producing company profits and the tax take of federal and state governments. With Alaskan wellhead prices well below the floor level of US "windfall" taxation, the tax burden has shrunk to an estimated $3.35 a barrel currently. Reduced corporate income tax rates from 46% to 34% starting in 1987 has also helped producers. However, Washington claims that the companies may owe $200-million in "windfall" profits taxes for 1984 and 1985 due to disparities in pricing and pipeline charges among the various Alaskan oil producers (PIW June 13,'83,p3).

The settlement of a 7-year legal dispute over Alaskan pipeline tariffs has also put an extra squeeze on profits since 1986, with the Trans-Alaskan Pipeline providing 15% of North Slope profits now compared to 30% in 1985. Aimed at fostering greater competition for North Slope leases, the resolution with the seven owners (BP 50%, Exxon and Arco

20% each, and the rest split between Mobil, Phillips, Union and Amerada Hess) sharply reduced tariffs, settled back claims of overcharges and put the pipeline on a real-rate-of-return basis starting in 1986 (PIW Nov.4,'85,p8).

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US Rebuff Doesn't End London's Plans For Oil Futures Role

The existence of a semi-secret and unofficial "mini-Brent" North Sea market might help London's International Petroleum Exchange win a central role in the globalization of oil futures dealing. Mini-Brent could provide a model for the IPE as it prepares another relaunch for its failed Brent futures contract following the New York Mercantile Exchange's refusal to trade US crude futures in London as a joint venture (PIW Jan.25,p8). Shocked and disappointed by Nymex's rejection of joint trading of West Texas Intermediate futures, the IPE is considering a number of alternative options, with a restyled 1,000-barrel Brent contract based on cash settlement rather than physical delivery at the top of the list (PIW Jan.25,p8). Other possibilities include a London-based West Texas Intermediate contract administered independently of Nymex, and a link to another US exchange such as the Chicago Board of Trade, which dabbled with oil futures several years ago.

Steady but largely unpublicized trade in the unregulated mini-Brent market leaves little doubt that demand exists for a financial tool of this type geared to European crude. Also known as the Brent partial market, and only reluctantly revealed to PIW by major players, mini-Brent is the brainchild of US investment banks. But its future is now in doubt due to new UK laws which may leave room for the IPE to take over instead. Mini-Brent works because the investment banks are willing to buy and sell futures contracts for part-cargoes of Brent in 50,000 barrel increments under their own set terms, normally closing out at an agreed cash-settlement price as 600,000-barrel forward Brent cargoes begin to trade in the physical market. However, this trading could fall foul of the forthcoming UK Financial Services Act (PIW Jan.11,p2). The IPE, as a recognized futures exchange, might win approval of a similar standard contract, using well-established procedures of exchange-of-futures-for-physicals for participants wanting to take delivery. The IPE is now seeking industry advice on how to tailor a new contract, but there's virtually universal agreement that simply restyling the existing 1,000-barrel contract won't work.

Even with its poor track record in marketing and planning, the London futures exchange is still eager to launch its own crude contract that will spark trade both locally and from Mideast and Far East time zones, largely out of New York's normal reach. It plans "some form of significant trading incentive scheme to encourage initial participation" and scope for broader membership, aimed at attracting more active floor traders. While Nymex boasts almost 800 members and last year traded an average 40-million b/d, there are currently just 57 authorized IPE dealers. There's general dismay in European trading circles over the Nymex's "parochial" decision not to come to London, coupled with the recognition that Eastern Hemisphere traders increasingly want to use crude futures (PIW Dec.7,p6). The IPE has already been approached by the Singapore International Monetary Exchange on possible broad cooperation.

●

Africans In Opec Find Alternatives To Direct Discounting

Like the big Mideast exporters, Opec's key African members are moving fast to cushion themselves against rapid swings in output even in a weak market. But they are using very different means to achieve the same ends. Resisting straight market-related pricing, the Africans are looking to product sales, processing deals of various kinds and enhanced margins for foreign equity producers to sustain volumes. Though techniques differ, almost all Opec exporters are adapting to an oil market in which some price volatility is seen as inevitable, making maintenance of sales to key customers in ways that cause the least market disruption a top priority (PIW Jan.25,p1). The various methods reflect marketing strengths of individual producers and preferences of traditional customers, among other factors.

Among African producers, Libya appears to have significantly reduced its vulnerability to short-term market swings. Though volume has fallen somewhat, Tripoli seems to be offsetting much of the recent loss of up to 200,000 b/d in third-party crude sales to traders without flooding the Mediterranean with discounted crude. "They've

minutes. I will give a two-minute warning when thirteen minutes have elapsed.

The first party to give their opening statements will be the State of Alaska. Mr. Maynard?

MR. MAYNARD: Thank you.

OPENING STATEMENT ON BEHALF OF THE STATE OF ALASKA

BY MR. MAYNARD:

Commissioner Agi, Commissioner Knowles, Commissioner Guess, Commissioner Whiteaker, and Judge Wilson. My name is Robert Maynard. I'm an Assistant Attorney General with the State of Alaska. And again with me are, Mr. Robert Loeffler and Mr. Ed Tome.

The State in this opening statement wishes to make primarily two points and that is, first, that the State is relatively indifferent to the outcome of the intrastate tariff dispute. Secondly, that we believe the APUC Staff's and other's attack on the settlement as being devoid of any public policy or any public interest, we believe that that attack is misplaced, is inappropriate and is overstated.

We believe the settlement should be approved as a fair and reasonable resolution of what might otherwise be an interminable dispute. In fact, almost all of the actual economic interests involved in this tariff dispute approve of this settlement, including over 99 percent of the shippers over the intrastate line. We believe that whatever

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resolution this Commission gives to this settlement proceeding, whether it grants the settlement or whether it decides a continued litigation is appropriate, we believe that this settlement should at least be accurately portrayed, which we do not believe it has been in this proceeding to date.

With regard to the interest of the State of Alaska at this point in the in-state tariff dispute, the APUC Staff basically says that the State will lose $5 billion by this settlement. Now, that is a number based on the interstate numbers on this pipeline as a whole. We believe that is high by at least a factor of two. But to use it as a basis for complaining against the intrastate tariff, we believe is misleading. The State's interest is not nearly that amount. In fact, we are probably indifferent. The reason for that is two points.

First, there is a crediting provision with regard to the settlement that was actually taken from the stipulation entered into by all parties in the interstate tariff dispute, including the APUC Staff. That crediting provision would provide that intrastate revenues would be credited against the interstate revenue requirement. Thus, the more that is collected on the intrastate tariff the less that needs to be collected on the interstate tariff.

The second reason, which I will explain in some detail

to come, is that the State's revenues are almost all based on the interstate tariff, on out-of-state shipments. The State gets its revenues off the pipeline in three forms; one, is by the effect on the severance tax; another is the effect on the royalty; the third is the effect on the corporate income tax.

Now, the severance tax and the royalty when we leave it with the producers, when we take our royalty in what is termed "end value" is based on what the companies report to the State for their dispositions of oil. Almost all of those dispositions are out-of-state dispositions that depend on the interstate tariff.

It is true the State sells a large proportion of its oil in-state to in-state refiners, and that is shipped over the intrastate tariff, which is the subject of this Commission's hearings. But the price that the State receives on its in-state sales of contracts to Chevron, Tesoro and MAPCO is based on the companies' reported prices. The term is that we get what we would have gotten if we had left that oil end-value with the producers. And that price is determined by the companies' reported prices which is in turn based on the in-state tariff -- interstate tariff. Excuse me.

The third factor is the corporate income tax, but because of the crediting provision, it doesn't matter what

the in-state tariff is, the overall revenues will be the same. So the corporate income tax is not affected.

Thus, at best, the State is indifferent as an economic basis on its financial interest on the intrastate tariff.

The question arises of why are we in the case. Well, initially we were in the case for two reasons. The first reason was that at that time, we wanted to have the same position presented before the then APC and the FERC. We believed that inconsistent result between the APC's ruling could hurt our interstate case before then the ICC to become the FERC.

Second, at that time it was believed that the Attorney General's Office could assist in a great degree with at that time what perceived to be greater resources in prosecuting the in-state case. At the present time neither of those two particular points apply. FERC has ruled on the interstate tariff, and has also had a general methodology to be applied to other pipeline tariffs.

Second is a budget crisis. A request for a certain amount of money has been basically slashed 25 percent in the internal reviews, and I don't believe there's much likelihood of getting a whole bunch back during the legislative process. Because of that, whatever the Commission's resolution of this dispute, the State will not be presenting an independent viewpoint before the Commission on this

pipeline case or probably other pipeline cases. The State's economic interest is not there and we believe the APUC Staff has sufficient resources to prosecute the in-state case if, in fact, this Commission decides to continue on with the case or other pipeline cases.

Why are we here necessarily with such a great presence, with a witness and making statements? We may not have been here in such a great presence if the settlement had been accurately portrayed and if the presentations against the settlement had been based on basically intra-state concerns. But neither of those two points have been the case. The attackes have inaccurately portrayed the settlement and have taken basically an attack against the underlying policy as being totally devoid of any public interest in this settlement. Because of that we would at least like to have some record that there might be some reasons why this settlement is in the State's interest and to rebut some of the charges that have been made.

Mr. Horst will present in some detail in his testimony the inaccurate portrayals of the settlement process itself or the settlement itself. But overall, the APUC in its papers has basically attacked the settlement as losing the State money, $5 billion and as having no public interest. We believe that is overstated.

Now, we want to make it clear from the outset that

we believed and still do believe that a litigated conclusion to this case should give the State substantially more money and a substantially better position than it's getting out of the settlement. The numbers we gave publicly a couple of years ago during the legislative debates was about $2½ billion was what we believed a reasonable litigated conclusion to this settlement would give the State. But there are two problems with that.

First, there was the risk that we wouldn't get that 2½ billion, that we wouldn't even get what we would get by this settlement. There were potential outcomes that would give the State substantially worse than what we got by the settlement, particularly considering the fact that there have been rulings by the FERC that would have given the State much worse.

Secondly, there was a severe problem of time. After eight years of litigation, even the ALJ in the case was saying that it would be ten years before a litigated conclusion would come to an end. That would only start the State's problem. We would then have to collect the money -- not from the pipeline shippers, but from the companies paying severance tax royalty and would have to chase down royalty in-kind purchasers, such as ALPETCO, who is now in bankruptcy. There were concerns there.

Now, no one in the long and sometimes acrimonious debate

argued about whether or not the TAPS settlement has been in the public interest. To my knowledge no one has ever stated that this settlement was a bad settlement in terms of the fact the State could have voluntarily gotten more from the companies. The debate has always been we should have continued to litigate; that the settlement may have been the best voluntary agreement you could have gotten out of the companies but you should have litigated this thing to its conclusion because you're going to win a lot more. And yes, if we had litigated we might have won more, we believe we should have won more, we believe we had a good chance of winning something more. But by the settlement we will at least gain three advantages; one, we gained substantial immediate relief. We got lower tariffs now instead of waiting ten years down the road. We gained certainty through the end of the century and avoided the possibility of endless yearly rate cases with stale records being constantly raised to the allenge to any long-term solution to the rate cases. And the State did achieve some long-term developmental interests by load tariffs through the end of the century, in fact, to the first decade of the next century which at various times throughout the state has been bantered as one of our main policy goals.

Now, we could discuss those policy goals at length, I would only have to give one example. And in fact is

not an example that was one of the driving forces of this settlement when we entered into it two years ago, but it does show why settlement sometimes and the certainty afforded by settlement can have good consequences.

The settlement already through fiscal year 1988 will bring approximately -- that means July 30th, 1988 -- will being approximately -- July 1, 1988, excuse me -- will bring approximately $800 million in benefits to the State. That comes to approximately from $230 million in refunds and between $300 and $350 million of annual tariff revenues over what the tariffs would have been if we had not entered into the settlement because, remember, without the settlement, tariffs would have stayed at the $6.01 rate until the end of litigation.

Now, the recent revenue projections, the January revenue projections just released by the Department of Revenue give the following unrestricted revenues coming into the State with the TAPS settlement for the next three years: fiscal year '87, $1.334 billion; fiscal year 88, $1.325 billion; fiscal '89, $1.374 billion. Now, the money coming in from the TAPS settlement for FY 87 and FY 88 again is $800 million. Total unrestricted revenues are $2.6 billion. The settlement is bringing in almost one-third of the unrestricted revenues the State is receiving.

For fiscal year '89 the settlement will almost bring

in a quarter of the unrestricted revenues, about 300 or 350 million of 1.4 billion; less than a quarter but almost a quarter.

The State is already facing a budget deficit of $900 million going into this fiscal year. It will be tough to imagine when another $800 million load would be on that.

Now, yes, we possibly could have gotten $2½ billion more ten years from now with interest, but to tell someone, to tell a student asking for a student loan they can get more money ten years from now but can't go to school this year; to tell an AFDC recipient they can get more money ten years from now but not enough money this year; to tell longevity bonus recipients, a senior citizen 70 years old, that ten years from now he might get a lot more money; for building roads, for building infrastructures, sewer, water, for all the things the State does -- economists, accountants, lawyers can put a time value on money. It's very difficult to put a time value on services and difficult to put a time value on the provision of the basic necessities of life to the citizens of the state. When you're giving -- the State's a hungry man. The question is, do you want a square meal now or a feast ten years later? I think most people when you're hungry would want a square meal now.

This is not to say that the opposition to this settlement is illegitimate. In fact, there are good reasons why

you might say that settlement is not appropriate, you shouldn't be settling these types of cases. There's disagreements about the risk that we face going on. There's disagreements about whether we need money now or later, whether we should do different things. There are legitimate reasons to argue in the public policy mode that maybe settlement is not appropriate. And in fact you will be hearing, no doubt, and from Representative Davis for one, legitimate reasons and concerns as to whether or not settlement on the interstate on the whole basis is an appropriate public policy. The previous governor, Governor Sheffield, believed that settlement was appropriate. There are legislators who do believe that settlements are appropriate, other people do not.

We are not trying to say that the issue is clear one way or the other. But when the APUC Staff says that there is no public interest in this settlement, we believe they are incorrect and overstating the matter. And when the APUC Staff and other people are trying to force the interstate settlement policy debate into this intrastate proceeding, we believe that is inappropriate because those policies were on the interstate side.

JUDGE WILSON: You have two more minutes, Mr. Maynard.

MR. MAYNARD: Thank you, Judge Wilson. The issue here

is whether or not the APUC will find the settlement to be a fair and reasonable resolution of the intrastate dispute. All the State is really asking for in this particular proceeding, whatever the outcome of this resolution, is that you give a balanced recognition of both the faults and the merits of the settlement as well as this settlement or any other negotiated conclusion.

We believe the central question is whether you have to determine whether this settlement must meet the just and reasonable standard or the fair and reasonable standard. If you do not believe the fair and reasonable standard is appropriate, it is our belief you do not need to reach the question of whether or not this settlement is just and reasonable, because we do not believe there is a record before this Commission to make that finding. We would ask if you do not believe the settlement can be resolved on the fair and reasonable standard that you simply dismiss it and go on with litigation, and the State will live with whatever outcome comes on. We think it is a shame it would happen, because with the intrastate proceeding it seems to us that all the people who have economic interest are willing to live with the settlement, and our particular resolution would allow those who oppose it to continue to oppose it. But that is the Commission's choice and we just simply ask for fair treatment of this settlement proposal.

Thank you very much.

JUDGE WILSON: Thank you, Mr. Maynard. We will now have the opening statement of the TAPS Carriers. Mr. Brose?

OPENING STATEMENT ON BEHALF OF THE TAPS CARRIERS

BY MR. BROSE:

Thank you, Commissioners, Judge Wilson. My name is Stephen Brose and I'm appearing today on behalf of the TAPS Carriers. I certainly intend to keep my opening remarks well within the allotted time, and I certainly don't intend to retrace in any detail the material found in our briefs or in the prepared testimony of our witness Mr. Richard Hildahl.

What I would like to do is to take this opportunity to try to put this case and your role in it into its proper context, because there has been far too much testimony and briefing on both sides that may tend to direct the Commission's attention away from the ultimate issues and either on to peripheral matters or issues that really aren't before you at all.

I'd like to start by emphasizing what the Commission is not being asked to do in this proceeding. First, as both Mr. Maynard and the reply briefs have made clear, the question or the lawfulness or even the desirability of the TAPS Interstate Settlement which governs more than 96 percent of total TAPS shipments is not at issue here.

That settlement, as you undoubtedly are aware, is solely within the province of the FERC and it has been approved by that Commission without qualification and is currently pending affirmance in the United States Court of Appeals.

All that's at issue here is whether the TAPS settlement should be approved as it relates to the less than 4 percent of TAPS movements that travel intrastate.

And so let's just be sure that we don't get too caught up in the rhetoric about the supposed overall impact of the TAPS settlement, because even if the calculations that appear in the APUC Staff's presentation were correct, and we believe we have shown that the Staff's assessment isn't even remotely in the ballpark, they're simply of no relevance whatsoever to this proceeding.

Second, and the testimony and the issue statements appear to have obscured this as well, you are not being asked to approve for all time the rates produced by the TAPS settlement methodology, what we call the TSM. The settlement is an agreement between the TAPS Carriers and the State of Alaska and it's effect is to establish a formula that those parties agree will govern the setting of a ceiling on TAPS intrastate rates. In other words, the Carriers have simply agreed that they will not file rates above those produced by the TSM formula, and the State has agreed that it will not challenge rates that are filed at or