SB
2001
(FILE 12)
10/22/07

1. Gavel In & Call to Order : Note time – members present

I CALL THE SENATE RESOURCES COMMITTEE TO ORDER ON MONDAY, OCTOBER 22, 2007. LET THE RECORD REFLECT THAT IT IS _______ A.M..

PRESENT ARE:
Vice-Chairman Senator Bert Stedman
Senator Gary Stevens
Senator Lyda Green
Senator Lesil McGuire
Senator Bill Wielechowski
Senator Tom Wagoner
& myself, Senator Charlie Huggins

2. SB 2001 OIL & GAS TAX AMENDMENTS

Conclusion of Administration's Modules: "A Topical Analysis of the ACES Bill"

Robert E. Mintz, K & L Gates

To be followed by Legislative Advisors and Consultants

Dan Dickinson, Legislative Budget & Audit Consultant
Steve Porter, Legislative Budget & Audit Consultant
And
Don Bullock, Legislative Counsel

Welcome:

Ask the speakers to introduce themselves for the record.

3. Announce: We'll be back tomorrow @ 9 AM, scheduled to go the the day with Industry Independents and Associations.
Returning in the early evening for public testimony @ 6:15 PM

6. Meeting adjourned @ _________.

ALASKA STATE LEGISLATURE

Sen. Charlie Huggins, Chair
Sen. Bert Stedman, Vice Chair
Sen. Lyda Green
Sen. Gary Stevens
Sen. Lesil McGuire
Sen Bill Wielechowski
Sen. Thomas Wagoner

State Capitol, Room 119
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Senate Resources Committee

Butrovich Rm 205

Monday, October 22, 2007

10:30 a.m. - 5:00 p.m.

11:00 11:30

DELAYED UNTIL ~~10:30~~ A.M.

AGENDA

SB 2001 - Oil and Gas Production Tax

Administration Sectional Analysis of SB 2001
Marcia Davis, Deputy Commissioner, Dept. of Revenue
Robert Mintz, Preston Gates

Legislative Advisors/Consultants
Dan Dickinson, Legislative Budget & Audit Consultant
Steve Porter, Legislative Budget & Audit Consultant
Don Bullock, Legislative Counsel

A Topica [redacted] f the

K & L Gates
21, 2007

A Few Background Basics:

The oil and gas production tax . . .

- is in AS 43.55
- is in addition to royalties, property tax, and income tax
- has existed since before statehood
- generally applies a percentage tax rate to the *value* of oil and gas produced
- unlike royalties, applies to production from private and federal leases as well as state leases

Core Provisions of HB 3001 (enacted in 2006)

- **AS 43.55.011(e) – (i): tax levied on value of oil and gas produced**
- **AS 43.55.160: calculation of taxable value of oil and gas**
- **AS 43.55.165 & .170: determination of upstream costs that may be deducted in calculating taxable value of oil and gas**

(cont.)

Core Provisions (continued)

- AS 43.55.023 & 43.55.024: new tax credits
- AS 43.55.020(a): monthly estimated tax payments and final payment on March 31 of year following production (because this is now an annual, not a monthly, tax)
- AS 43.55.030(a): just one annual return

AS 43.55.011(e) (current)

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to 22.5 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160 . . .

- *Note*: "production tax value" is net value

AS 43.55.011(e) (continued)

Exceptions:

- Tax does *not* apply to
  - state or federal share
  - landowner's royalty share (which is subject to a different tax provision)
- Cook Inlet production subject to ceilings based on past taxes (AS 43.55.011(j) & (k))
- North Slope production subject to a minimum tax depending on price of ANS (AS 43.55.011(f))

AS 43.55.011(g) (current)

- For each month when the net value of a producer's oil and gas exceeds $40 per barrel, the tax rate under subsec. (e) is in effect increased by ¼ of a percentage point for each dollar per barrel over $40
- Informally known as "progressivity tax"
- Gas and oil are added together by treating 6 million Btu of gas as equivalent to one barrel of oil (see AS 43.55.011(h), 43.55.900(17), (18) & (24))

proposed SB 2001

AS 43.55.011(e) (new)
Bill sec. 15

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to the production tax value of the taxable oil and gas as calculated under AS 43.55.160 multiplied by the tax rate determined under (g) of this section.

AS 43.55.011(g) and (h) (new) Bill secs. 17 and 18

- "The tax rate . . . is 25 percent plus" the progressivity tax rate
- The progressivity tax rate is 1/5 of a percentage point for each dollar per barrel over $30 net value
- Progressivity is calculated on an annual, not monthly, basis

North Slope Tax Floor
Bill sec. 16

- New AS 43.55.011(f): minimum tax is 10 percent of gross value at the point of production of oil and gas from a unit (or nonunitized reservoir) that
- (1) has produced a cumulative total of 1 billion barrels; and
- (2) is producing over 100,000 barrels a day (average during the most recent calendar year)

Cook Inlet Tax Ceilings
Bill secs. 19 and 20

- Tax ceilings are not changed (conforming amendments only)
- Note: sec. 21 of the bill adds language dealing with Cook Inlet tax credits to be consistent with sec. 55, which clarifies how excess lease expenditures are treated

AS 43.55.160 (bill secs. 52-55)

- The basic principle is unchanged: taxable value = gross value at the point of production minus lease expenditures
- Wording has been changed:
- (1) monthly values are no longer needed (progressivity is now annual)

AS 43.55.160 (cont.)

- (2) bill is clearer and more specific on when a producer may or may not use lease expenditures for operations at one location as deductions for oil and gas produced at another location
- These rules are necessary to implement the different tax treatments of different areas and fields (Cook Inlet ceilings, North Slope floor, tax credit under AS 43.55.024(a))

AS 43.55.160 (cont.)

- For instance:
- (i) To avoid undercutting the tax floor, deductions may not be "exported" from units subject to the tax floor (AS 43.55.160(f)(2))
- (ii) To avoid double-dipping re: Cook Inlet tax ceilings, deductions must first be used up in Cook Inlet and may not be shielded by the ceilings (AS 43.55.160(h) and (i))

Prudhoe & Kuparik

AS 43.55.165 (bill secs. 56-59, 64) Lease Expenditures

AS 43.55.165(a) and (b) are rewritten and reorganized:

- (1) for more clarity
- (2) to limit lease expenditures to only what the Department of Revenue allows by regulation

Lease Expenditures (continued)

marsha: operationally more sound & durable

- AS 43.55.165(c) and (d) are repealed.

- Those provisions allowed the Department to substitute cost billings under unit operating agreements in place of the general standards for determining lease expenditures.

Lease Expenditures (continued)

- AS 43.55.165(e): the list of *excluded* costs is expanded:
- par. (6) – costs arising from violation of law or noncompliance with lease or permit obligation
- par. (15) – all dismantlement, removal, & restoration costs (costs are prorated for past production under current law)

can't deduct

from suggestion

("DR&R")

yes/SGL

state should subsidize exploration & new developments not dismantlement

Lease Expenditures Exclusions (cont.)

SB 80 esk

can't deduct

- par. (19) - repair or replacement of facilities or equipment associated with an unscheduled drop in production or an oil spill or unpermitted release

wagoner. do we know yet how much Opex was deducted for corrosion probs. Davis: don't know

- par. (20) – crude oil topping plant (but deduction is allowed for value added of product used in lease operations)

cost of acquiring, constructing or operating - not deductable
Admin thinks it's not a direct cost - very indirect
but value of product is deductable.
cost now $300 million to modify - let alone build

Tax Credits under AS 43.55.023 Bill secs. 26-31, 65

Changes to .023(a) – qualified capital investment expenditure credits :

- Only 50% of a credit may be used the first year
- For exploration, requirements are conformed to changes in .025 credits (see below)

helps smooth out the lumpiness caused by credits taken in any one yr.

predates PPT Legislation

CH? feed back on this? Marsha none but would effect probably smaller co's like Pioneer

→ Bring back amendment that helps smaller operations to use credits in 1 yr. – Sen Weil. thinks good also

Tax Credits under AS 43.55.023 (continued)

Changes to .023(a) (continued)

- Credits for capital expenditures in a unit subject to the tax floor may be applied only against tax on oil and gas production from that or another unit subject to the tax floor

applies to legacy fields

Tax Credits under AS 43.55.023 (continued)

Change to .023(b) – carried-forward annual loss credit :

- **No carry-forward for unused lease expenditures for units subject to the tax floor**

accommodates smaller players to use capital credits

Tax Credits under AS 43.55.023 (continued)

Change to .023(d) – transferable tax credit certificates: - explorer or producer who doesn't have tax liability can still use – helps

- Two certificates will be issued, each for half of the credit
- One certificate cannot be used until the next year

State to bring back conforming lang. to not penalize small operators

Tax Credits under AS 43.55.023 (continued)

New subsection .023(*l*) :

- Makes clear that a tax-exempt entity may not obtain a transferable tax credit certificate

Stevens - a native corp would not be taxed? !

Tax Credits under AS 43.55.023 (continued)

AS 43.55.023(i) is repealed:

- This eliminates the transitional investment expenditure credits for investments that were made during the five years before April 1, 2006.

Pedro V Meures thought "clawback" was a bad idea - would not have used it

Marsha: aware of some filings under this will work to see which small producers are affected

Tax Credits under AS 43.55.025
Bill secs. 36-44

- Sec. 36 - Existing 2016 sunset is uniformly applied
- Secs. 37 & 43 - Exploration well credit expanded to delineation wells within 2 drilling seasons (rather than being limited to discovery well or dry hole)
- Sec. 37 - Well must be completed or abandoned, not just suspended, before credit may be claimed

Tax Credits under AS 43.55.025 (continued)

- Sec. 37 - Costs excluded if due to gross negligence or health/safety/ environmental violation
- Sec. 38 – Clearer definition of requirement for new exploration target; 3-mile requirement deleted for Cook Inlet; DNR evaluation required in advance and after drilling

confined to statute that deal w/ health safety
DEC & OSHA regs.
if operator violates statute then cannot deduct expenses associated w/ that

Tax Credits under AS 43.55.025 (continued)

- Sec. 39 – Data submission requirements are more specific
- Sec. 39 – Well data confidentiality limited to 24 months
- Sec. 39 - Two certificates will be issued, each for half of the credit; one certificate cannot be used until the next year

Tax Credits under AS 43.55.025 (continued)

- Sec. 39 - Makes clear that basic information about tax credit is public
- Sec. 40 - Makes clear that a tax-exempt entity may not transfer a tax credit certificate
- Sec. 44 - New five percent tax credit available for old seismic data if DNR determines that acquiring the data for public distribution is in state's interest

State Purchase of Tax Credits Certificates – Bill secs. 45 & 63

- New AS 43.55.028 establishes oil and gas tax credit fund to purchase credit certificates from explorers or small producers that have no tax liability to apply credits against
- Funded by appropriation of a percentage of production tax revenues
- Replaces existing cash refund authority under AS 43.55.023(f) (repealed by bill)

State Purchase of Tax Credits Certificates (continued)

- Retains existing criteria for refunds except eliminates $25 million maximum

Payment of the Tax
Bill secs. 22-25, 51

- Current system of monthly installment payments and final payment on March 31 is retained
- Installment payments now take account of the tax floor for units subject to the tax floor and also take account of Cook Inlet tax ceilings
- Installment payments do not take account of progressivity rate

— Interest rate · a market rate during year of filing - after filing date = "statutory rate" approx 11% compounded

— old mechanism DID take into account progressivity

— new (proposed) protects co's who might fall out of compliance over progressivity (which is annual calculation) that's hard to anticipate monthly

Payment of the Tax (continued)

- **AS 43.55.110(f), Bill sec. 51 – Gives express authority to Department to require tax payments to be made electronically**

most tax payers do pay electronically
this mandates it – removes any question

CH – what forms of pyt do get now
Marsha – (1) electronic wire
(2) cashiers cks
but not Mandated – which leads to "cks in the mail" syndrome

Reporting Requirements
AS 43.55.030, 43.55.040

- Bill sec. 46 – Makes clear that every oil or gas producer must file an annual return, whether or not tax is due
- Bill sec. 46 - Expands the list of specific information requirements for returns (note: Department retains general authority to require more information)

Reporting Requirements (continued)

- Bill secs. 47 & 49 – Additional penalty of up to $1,000 per day for late filing or nonfiling of required returns or reports
- Bill sec. 48 – Requires explorers or producers to file an annual statement on expenditures (or adjustments) even if no oil or gas is produced during the year

- Filed electronically – Requirement in the bill
- not an onerous reporting [illegible]

Reporting Requirements (continued)

- **Bill sec. 48 – Makes clear that the Department may also require monthly reports from producers, explorers, and operators**
- **Bill sec. 49 – Adds express authority for the Department to require reporting of forward-looking information for revenue forecasting purposes**

Reporting Requirements (continued): Bill sec. 51

- AS 43.55.110(e) – Gives express authority to Department to require returns and reports to be filed electronically

CH asked the question - re reporting -
- the new statutes allow the Dept to specify the form of elec filing

Confidential and Public Information

- AS 38.05.035, Bill sec. 2 – broad authority for DNR to share oil and gas lease related information with DOR for purposes of administering the production tax
- AS 43.05.230, Bill sec. 13 – broad authority for DOR to share production tax related information with DNR

Confidential and Public Information (continued)

- Under both provisions, confidential information is still confidential
- AS 43.55.890, Bill sec. 61 – Makes clear that Department of Revenue may publish extensive production tax information aggregated among at least three producers or ~~explorers~~ three

- clarifying provision

why 3 & not 2? Sen Stevens -

MP Dept of law in looking at Fisheries side standard was 3 -
It is a standard that has worked well

Additional Administrative Improvements

- **AS 39.25.110, Bill sec. 10 – oil and gas auditors placed in exempt service**
- **Transition provision, Bill sec. 67 – current employees may opt to stay in classified service**
- **AS 43.05.260, 43.55.075, Bill secs. 14, 50 – statute of limitations for production tax is six years, not three years**

· addt'l info. the dept needs addt'l time to audit & enforce tax laws.
· A considerable time needed - by both parties - extensions allowed now.

Additional Administrative Improvements (continued)

- **AS 43.55.075(b), Bill secs. 1, 50 - Legislative confirmation of Department of Revenue's interpretation of statute of limitations as applied to events that retroactively change amount of production tax or credit: period of limitations begins to run when a return is filed reflecting the change**

· examples RCA or FERC refunds ·
asking legis to confirm existing interpretation of law

Additional Administrative Improvements (continued)

- AS 43.55.110(g), Bill sec. 51 – Gives express authority to the Department of Revenue to issue advisory bulletins interpreting production tax statute and regulations for guidance of taxpayers and others; non-binding unless Department provides otherwise

. Dept not doing because of Broad interpretation because courts would want regulations -

Transition, Applicability, and Effective Dates

- **Bill secs. 66, 72 – Most substantive changes in the production tax are prospective beginning Jan. 1, 2008**
- **Bill secs. 66, 71 – Changes to lease expenditure exclusions and use of unit operating agreements for lease expenditures are retroactive to April 1, 2006**

*exclusions
+ Repair Replacement - DNR
* Replacement etc.

CH- Comment - why didn't we do in Regular session w/ Retro effective dates. (he requested no answer) Just the question

Transition, Applicability, and Effective Dates (continued)

- **Bill secs. 66, 71 – Statute of limitations extension applies to still-open periods and retroactive to April 1, 2006**
- **Bill sec. 71 – Clarification that tax-exempt entities may not transfer tax credits applies back to beginning of the respective tax credit provisions**

need to specify the retroactivity

023: (66)
025: 4/1/03

Most other provisions of the bill take effect immediately.

Provisions 4/06. the Reg can be retroactive to that date.

Auth to immediately begin Reg but not in effect until Jan 2008.

Transition, Applicability, and Effective Dates (continued)

- Bill sec. 73 – Most other provisions of the bill take effect immediately
- Bill secs. 68, 70 – DOR and DNR may start developing regulations immediately, and regulations may be retroactive to applicability date of the statutory provisions they implement

Senate Resources

Comments on Governor's ACES Proposal

Steven B Porter
10/22/2007

-Stability

-Alaska's Prospectivity

- ACES Incentives

-Summary

Senate Resources

Comments on Governor's ACES Proposal

Steven B Porter

10/22/2007

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Stability

1) Decision on Prudhoe Bay Satellites - Borealis, Midnight Sun, Orion, Polaris, Point McIntyre, and Aurora are integrated and collectively managed. Merely implemented the intent of the statute. When you consolidate wells with PBU facilities the regulations contemplate consolidation for tax purposes.

Application of the law not a change in law.

2) PPT tax. The producers have generally opposed any changes to the ELF prior to the SGDA negotiations. They liked the economics of ELF but knew they were going to have to agree to some change in order to get

1st change in stability world.

   a. Fiscal certainty under their contract
   b. They were also hoping for contract approval if they agreed to the change
   c. They lost on all counts.
      i. They did not get the tax they "agreed to"
      ii. They did not get any type of certainty on the tax
      iii. They did not get the contract

3) The governor has called you back to review the tax because of the "cloud" on the tax. I don't think this review will cause the world to see you as unstable. The industry will certainly say it is true, but anyone who really looks underneath their rhetoric will know the truth. They also know the truth. This is merely an evaluation of what was done – with a possible early mid-course correction.

4) If you change the tax now and change it again during the regular session, there may be a problem.

Alaska's Prospectivity

1) Oil
    a. State lands- less than 20% of the future potential are on state lands where we receive both royalty and tax.
        i. Puddles
        ii. Heavy Oil – will come back to this
    b. NPRA – around 30% of future potential is in NPRA
        i. No royalty but ½ the royalty comes back to the state first as impact aid, then to fund PCE then another fund before it has a possibility to get to the general fund. Of the millions of dollars that the state has received from NPRA I don't think any of it has reached the general fund.
        ii. Taxes – you still get taxes. But high costs will result in high opex and capex.
    c. Offshore OCS – over 50% of future potential is in the OCS
        i. No royalty
        ii. No taxes
    d. What is the future vision for oil
        i. Gov should go to congress and get us the same as the Gulf States have. They get a share of the OCS revenues because the feds recognize that the local state jurisdictions are impacted by OCS development – and they can oppose it and prevent it from proceeding forward
            1. This should be before shell drills any exploration wells

2. Should work with the NSB to make sure that the operations in the OCS minimize the impact to the environment and local communities and subsistence culture

ii. Heavy oil should be encouraged because it has the greatest chance on state lands of contributing to the future revenue stream of the state

1. One of the slides yesterday showed the industry doing stress case economics at $40. Commissioner Galvin stated that heavy oil will be impacted around $41 dollars from the implementation of the 10% gross tax which means that we may actually create a situation where we have prevented or slowed one of the most prospective oil reservoirs on state lands by passing the gross minimum tax. The minimum tax looks like it was designed to penalize heavy oil not help it.

e. Alaska competitiveness –

i. We are a mature (between Colville and canning) province as far as oil is concerned. Geology is king. Heavy oil and puddles

ii. NPRA has larger potential in the Alpine type range

iii. OCS still has the elephants but at great cost and high environmental/legal risk.

2) Gas

a. Pedro said the gas pipeline was uneconomic

b. I would call it indeterminate

i. Four things needed to say economic or uneconomic

1. Costs of the pipeline
2. Future price of gas
3. Stability of the taxes and what they are
4. Internal Rate of Return/Project evaluation criteria

c. The submittal of the proposals will not change the above substantially unless the applicants accepts, transfers, or provides a way to handle some of the above risks to the state's and the shipper's satisfaction.

d. When the proposals come out at the end of November the state should review the proposals then evaluate how they can help the state move the project forward. The project is not a gasline through Canada or an LNG line to Valdez. It is monetizing the North Slope gas resource to the greatest benefit of the people of the State of Alaska. It may mean making adjustments to the law in January. It may mean taking a new course, it also may mean AGIA is working and all that needs to be done is to implement it.

3) Timing of development in general and gas pipeline development specifically.

a. A reasonable timeline for gas pipeline development is at least 10 years. Anything less than that you need to examine the proposal closely to make sure they are not shortcutting process that may impact them and the state in the future.

b. A reasonable timeline for oil development depends on proximity to existing facilities. E.g.,

i. Tarn took around 2 years and was probably one of the fastest because it was near Kuparuk.

ii 6 to 8 years is a better estimate for prospects that are within 25 miles of existing facilities.

iii. Around 10 years for projects that is more remote.

iv. These are rough rules of thumb that don't take in to consideration specific environmental, logistics, cultural and subsistence issues of a particular project - each of which could delay development for several years.

ACES incentives

1) Legacy fields and all other existing fields.
    a. Places a higher tax burden on them
    b. Takes away the TIE credits
    c. Ring fences certain credits.
2) Explorers
    a. Places a higher tax burden on them
    b. Gives them a guarantee of getting their tax credit giving them 2% to 3% extra on their transferrable credits
    c. Moves net operating losses to 25% carryover.
    d. The costs of the higher tax exceed the credit benefit.

Summary

Someone asked yesterday what the governor's economic policy should be regarding oil and gas.

I recommend a few things

1) Encourage heavy oil development; don't place penalties in front of it.
2) Work with Congress to get our fair share of OCS revenue before shell or any other oil company drills in the OCS.
3) Works with local communities to make sure their concerns are addressed before development proceeds and so that responsible development can proceed.

Senate Resources Committee SB 2001 Details

Presentation by Dan E. Dickinson, CPA
For Legislative Budget & Audit Committee
October 22, 2007

1. Rate etc.

- Caveats on government take statistics
  - Apples to apples comparisons very useful – but be very wary about plucking numbers from different studies
  - Need to look at rest of the fiscal system. For example, some governments encourage developing high paying jobs (low industry taxes), and pick it up in personal income and consumption taxes.

2. Progressivity

- Switch in factors
- Switch from monthly to annual typically means lower dollars
  - Spikes don't average out
  - Higher base – but won't capture as much upside
    - Less progressive
- Modeling Issue – requirements

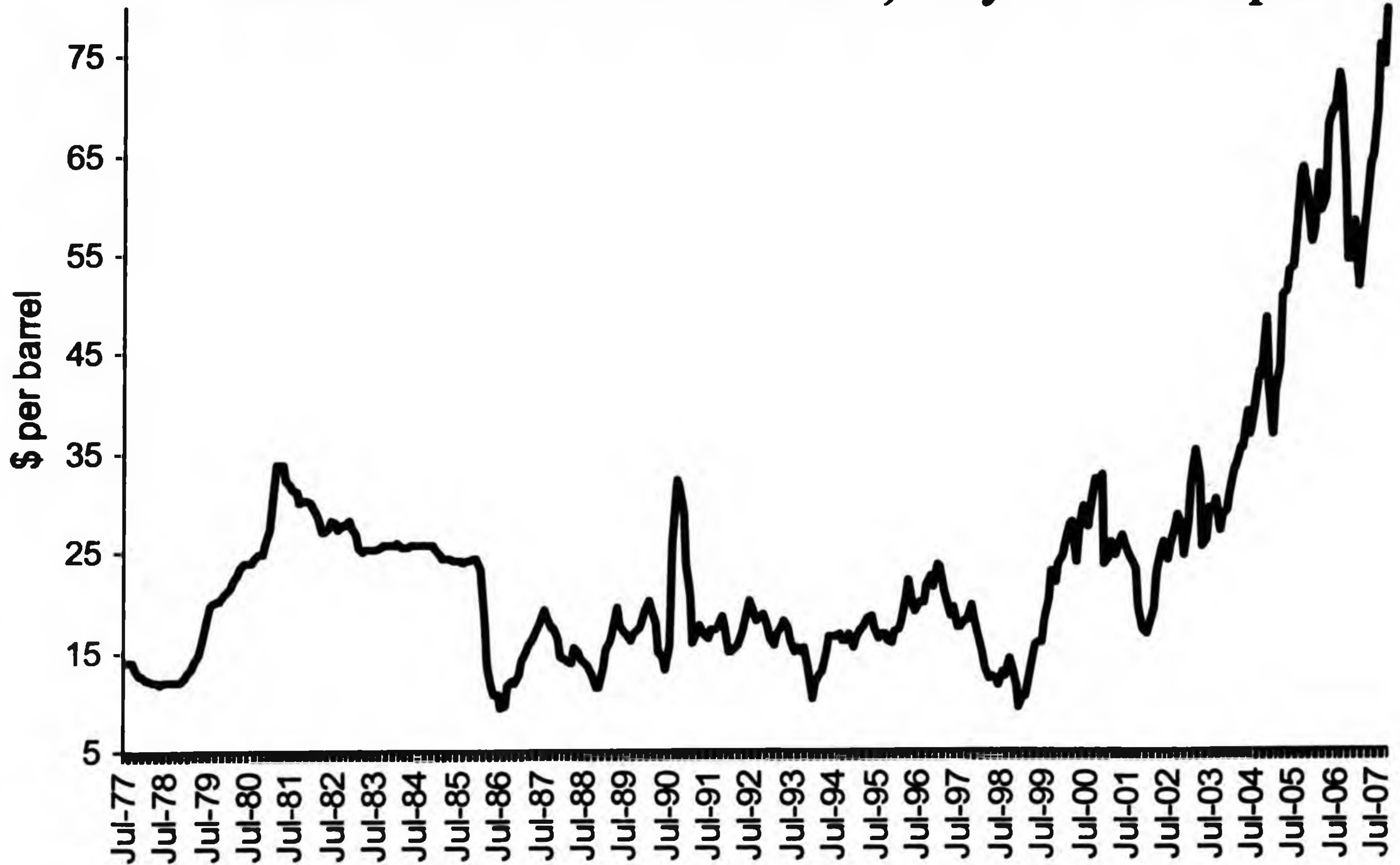
2. Progressivity

Comparing Annual and Monthly analysis of FY 2008 with hypothetical spike

	US West Coast Price/ bbl	Per Barrel Total Costs	Per Barrel Production Tax Value	Adjustment Converting Production Tax Value to Price Index	Price Index	Rate per Dollar of Price Factor	Incre-mental Progres-sivity %	Volumes (millions of bbls)	Progres-sivity Tax (millions of dollars)
	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	%	%	MM bbls	MM $
A	B	C	D= (B+C)	E	F= (D+E)	G	H= (F*G)	I	J= (D*H*I)
Monthly Analysis, $40 Adjustment and .0025% Parameter under Current Law									
Jul	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Aug	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Sep	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
Oct	51.43	(23.85)	27.58	(40.00)	-	0 25%	0.00%	20.7	-
Nov	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
Dec	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Jan	77.15	(23.85)	53.29	(40.00)	13.29	0.25%	3.32%	20.7	36.7
Feb	102.86	(23.85)	79.01	(40.00)	39.01	0.25%	9.75%	18.7	144.2
Mar	77.15	(23.85)	53.29	(40.00)	13.29	0.25%	3.32%	20.7	36.7
Apr	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
May	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Jun	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
								244.0	217.6
Yearly Analysis, $30 Adjustment and .002% Parameter, as Proposed									
Yr	60.00	(23.85)	36.15	(30.00)	6.15	0.20%	1.23%	244.0	108.5

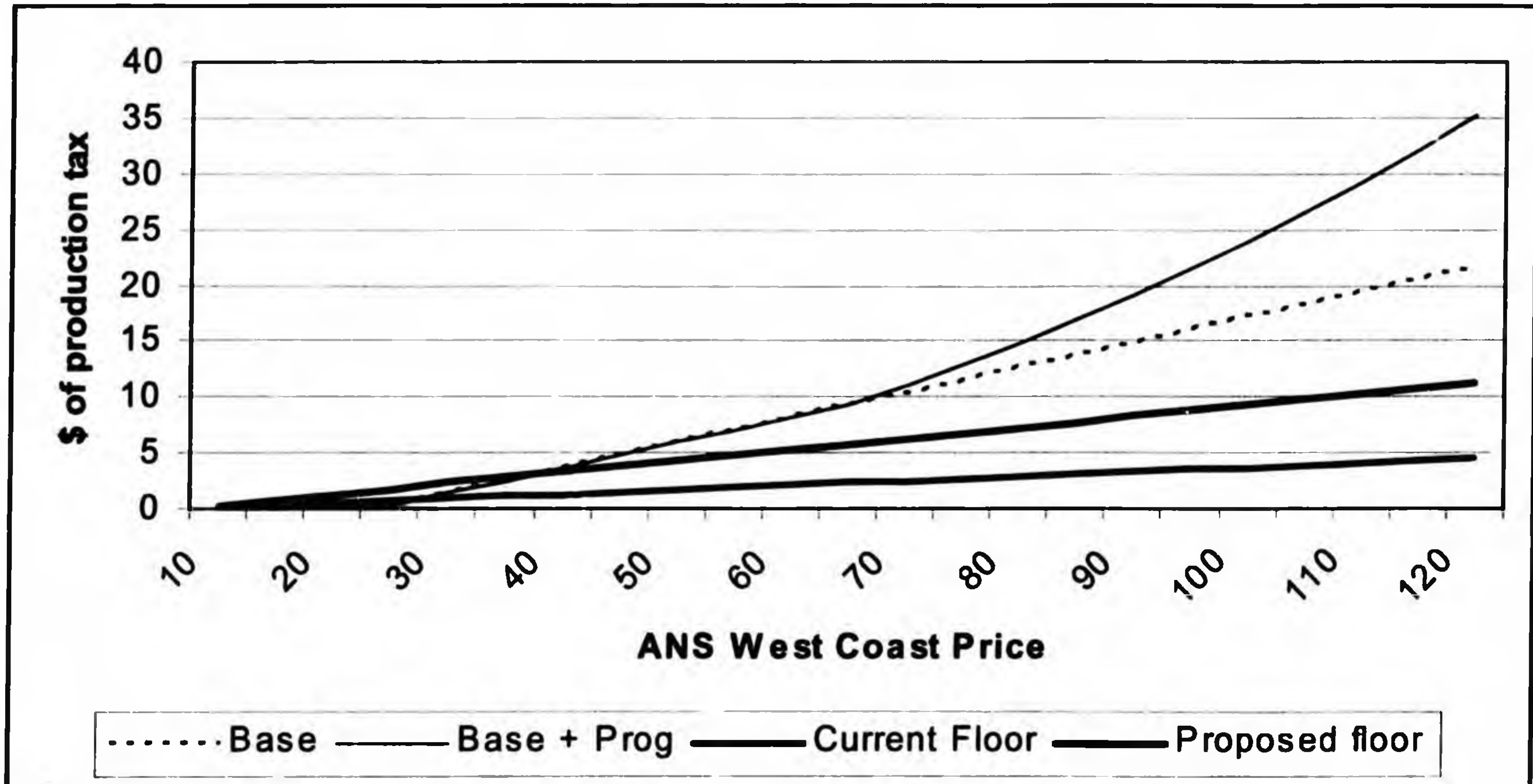
Source: Dickinson October 3 2007 report: NOT A PREDICTION

ANS West Coast Price, July 1977 – Sept 2007



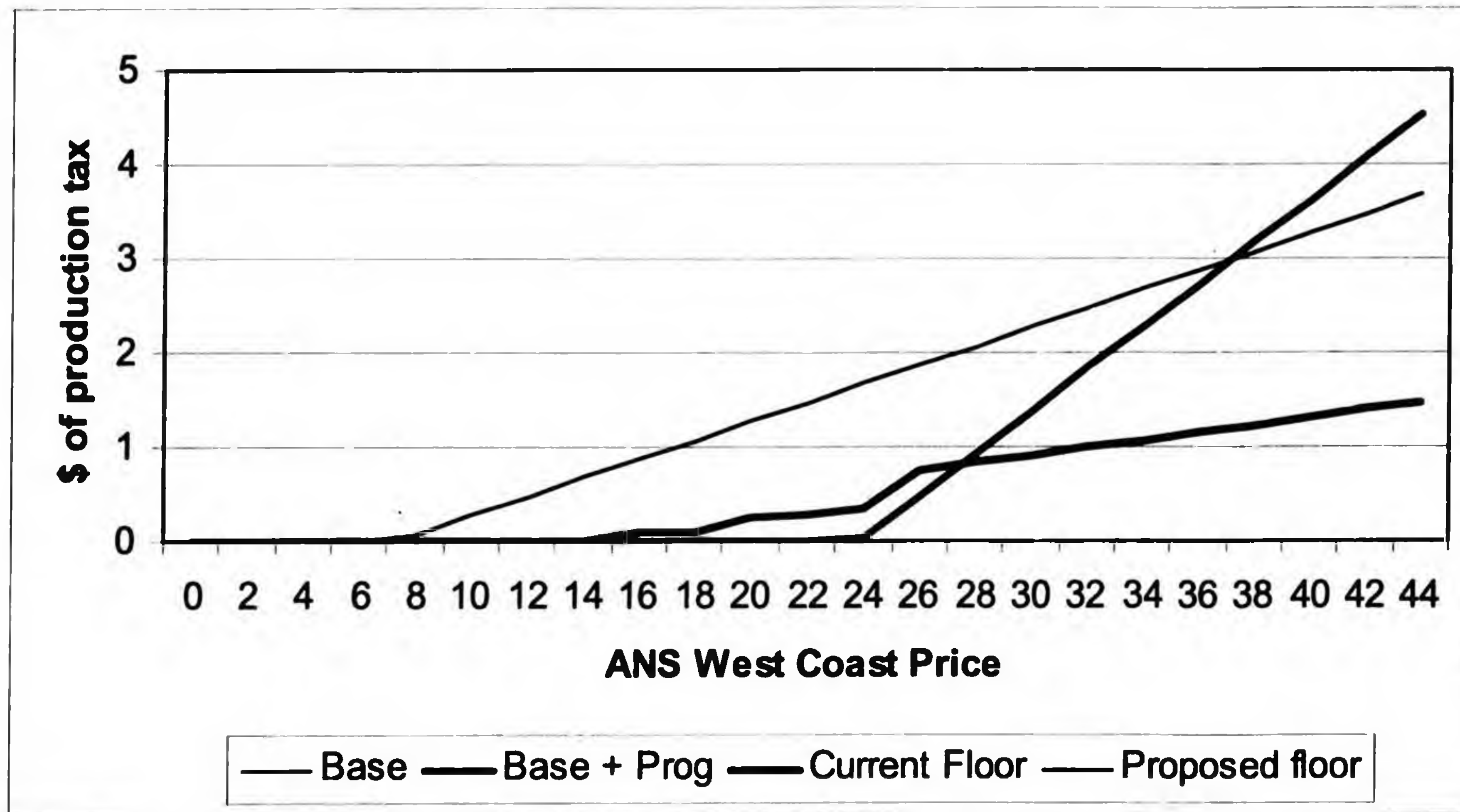
Source: Alaska Department of Revenue, Tax Division

3. Effect of Gross Floors – Low End



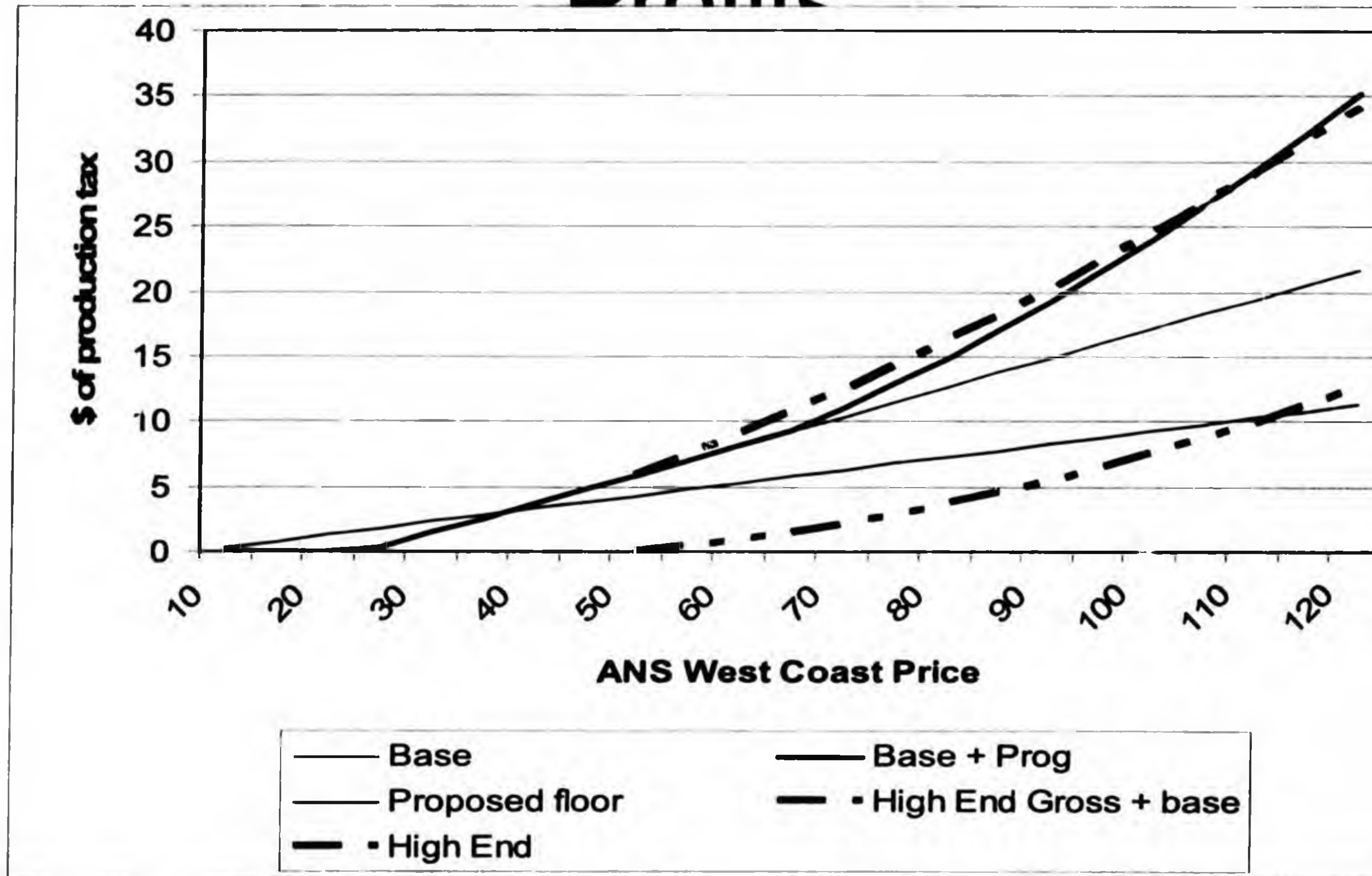
Cost assumption = $7.22 downstream cost, 16.63 upstream cost, barrels assumed to be legacy production

3. Effect of Gross Floors – Low End



Cost assumption = $7.22 downstream cost, 16.63 upstream cost, barrels assumed to be legacy production

3. Effect of Gross Floor- Windfall Profits



Cost assumption = $7.22 downstream cost, 16.63 upstream cost, barrels assumed to be legacy production

3. Legacy Ring Fencing – One Way

- Proposal is to ring fence Prudhoe Bay and Kuparuk into a "legacy field"
- Profits generated in Legacy Fields could be offset by investment credits and losses elsewhere (except when floor in place)
- Investment credits and losses generated in Legacy Fields could be offset by profits generated elsewhere

.023 Investment Credits

- .023 (b) Proposes to have loss carry forward credits calculated at the tax rate instead of 20%
  - makes sense to treat explorers and producers same
- .023 (d) proposal spreads credits out over two years-
  - because of difference between fiscal year and calendar year may not improve predictability that much
  - little actual fiscal effect after first year
- .023 (i) Proposed elimination of TIE credits
  - Compare rules to DNR Commissioner's proposed ability to grant credits for pre 2003 work in .025 (i)

.024 Non Transferable Credits

- Only proposed change would not allow these to be applied against the floor.

.025 Exploration Credits

- Proposal adds specific disallowances in .025(b)(3) for "costs arising from gross negligence or violations of health safety, or environmental statutes or regulations"
- Compare to lease expenditure disallowance in .165 (e) (6) for "costs arising from fraud, willful misconduct, gross negligence, violation of law, or failure to comply with an obligation under a lease, permit of license issued by the state or federal government"

.025 Exploration Credits

- Current AS 43.55.025 (c) says bottom whole must be three mile from previously drilled bottom hole, except in CI, if DNR determines “distinct exploration target”
- Proposal has three requirements – DNR approval before hand, must meet 3 mile requirement if not in CI, DNR approval afterwards.
- Change from rules to seeking agency approval.

.025 Exploration Credits

- Proposal would make data on non state lands more available to DNR and public as condition of credit.

- Using tax code for other (worthwhile) goals

.025 Exploration Credits

- Under current law, only additional wells spudded in a drilling season (150 days) can qualify for exploration credits
- Under proposal that figure is expanded to two drilling seasons (540 days)
- Shifting credits to explorers

.025 Exploration Credits

- Proposal will create mini-TIE allowing DNR to authorize tax credits for pre 2003 seismic work.

- Shift from rules to agency approval.

7. Allowable Lease Expenditures AS 43.55.160

- Proposal greatly simplified section because monthly calculations no longer needed for progressivity.
  - However, a monthly gross (destination value) based windfall profits tax would not require division of costs between months.

7. Allowable Lease Expenditures AS 43.55.165

- Under proposal allowable lease expenditures must be a defined in regulation
  - Switch from what is not forbidden is permitted to what is not permitted is forbidden.
- Can Joint interest billings be used? – although specific language is gone, appears DOR may still go down this road under its regulations

7. Allowable Lease Expenditures AS 43.55.165 (e) (6)

Current prohibition – “costs arising from

- fraud,
- willful misconduct or
- gross negligence”

Proposal adds

- violation of law; or
- failure to comply with an obligation under a lease, permit, or license issued by the state of federal government.
- Compare to proposed AS 43.55.025(b) (3)

7.Allowable Lease Expenditures AS 43.55.165 (e) (15)

- Dismantling, Removal and Restoration cash payments (DR&R) upstream
  - does not include common carrier pipelines
  - 'matching' accruals during operations not allowed
- Current law – allowed multiplied by a fraction of production before 2006 over total production
- Proposal totally disallows DR&R
- Even under current law much DR&R likely to never be deducted as no offsetting revenues.

7. Allowable Lease Expenditures AS 43.55.165 (e) (19)

- Proposal disallows costs arising in response to a problem which required an unscheduled reduction in production or resulted in an release of gas.
  - Regulations will probably define “unscheduled” -24 hour notice? Weekly? Annual? What if reduction amount is different from “scheduled” amount. What if one week of scheduled maintenance takes two weeks?
  - Encouraging capital investments to create Redundancy?
- Still allowed if “acts of God”

7. Allowable Lease Expenditures AS 43.55.165 (e) (18)

- Current law disallows 30 cents a barrel from what would otherwise be allowable capital costs
- This was described as dealing with the known corrosion issue.

7. Allowable Lease Expenditures AS 43.55.165 (e) (19)

- Compared with SB 80 approach which was built around the concept of "improper maintenance"
- Under current property tax law (AS 43.56), state actually taxes "replacement cost new less depreciation" or "as-if" North Slope facilities generated by cost studies. Millions of state and company dollars and spent on these models.
- Would probably build AS 43.55 "as-if" "well maintained" facilities

7. Allowable Lease Expenditures AS 43.55.165 (e) (19)

- Currently topping plants generate diesel on North slope that is used in production, and costs of plant are allowed.
- Under proposal cost of plant not allowed; instead "fair market value" of diesel less prevailing value of crude.
  - Market may not be broad
  - Specific plant under consideration

8. State Purchase of Credits (AS 43.55.028)

- Currently allowed if
  - Less than 50,000 bbls a day – i.e. not one of the big 3
  - Reinvest in state (including lease bids)
  - Taxpayer has no other delinquent taxes
  - Limited to $25 million a year
- Proposal eliminates $25 million limit
- Proposal establishes fund with percentage of tax revenues
- Removing cap not necessarily tied to separate fund.

9. Information AS 43.55.040 (5) & (6)

- Requires taxpayer "to file reports and copies of records that are considered by the department as necessary to forecast state revenues under AS 43.55"; $1,000 a day penalty
- Regulations will be needed to define
  - "necessary" (as opposed to say useful),
  - how far in advance (one, two, many years?)
  - how often the reports need to be updated (monthly, 1% change, change out three years…?
  - How far does due diligence have to go? Board of directors discussed 5 year plan?
  - Can State audit for information not provided, and assess 2amonthly 2 million penalty starting 6 years from now?

9. Information (general rule AS 43.05.230 – proposed rule AS 43.55.890)

- Currently under AS 43.05.230 (e) DOR can publish statistics with individual data combined so as to "prevent the identification of particular returns or reports"
- Proposal only requires combination of three taxpayers "regardless of whether the information …prevent[s] the identification of particular returns or reports"

9. Information (general rule AS 43.05.230 – proposed rule AS 43.55.890)

- Was described as "same as DOR does for Salmon Pricing Report"

- Alaska Salmon Price Report reporting rules are *not* removed from general AS 43.05.230 (g) – the general reporting tax confidentiality rules.

9. Information
Alaska Salmon Price Report

- Sec. 43.80.065. Confidentiality of reports.

Information in reports submitted under AS 43.80.050 , and price averages calculated by the department from the information in the reports, are public information, except that information that identifies or could be used to identify a particular fish processor is confidential.

9. Information Alaska Salmon Price Report

- "We use the following guidelines when evaluating confidentiality
  - If there are three or more processors for a given are, the information is reported unless one processor accounts for over 80% of total value, or two processors account for over 95% of total value.
  - If there are only one or two processors for a given are, the information is not reported"
    - From Cover letter - October 15, 2007 Alaska Salmon Price Report

9. Information - (AS 43.05.230(h))

- Proposal will require DOR to share information with DNR obtained under AS 43.55 – including forward looking information required by AS 43.55.040 (5).
- This may have competitive implications if DNR returns to markets as seller of royalty in kind (RIK) oil or gas.

9. Information – AS 43.55.030 (e) and (f)

- Proposes to set forth in statute the actual data required to be filed by taxpayers. Thorough summary of costs, volumes, sales, monthly estimates etc.

10. Statute of Limitations (Old general AS 43.05.260, new AS 43.55.075)

- Proposed extension from 3 years to 6 years
  - Currently frequently extended by mutual agreement of parties
  - Ability to assess$1,000 a day reporting penalties also extended

11. Auditors as Exempt Employees

- Good step to enter a competitive market.
- DOR income auditors also face national corporate income tax staffs. Income tax (both special oil and gas and general) generate over ½ billion dollars a year in tax revenues.

12. Other Admin – Information Management System

- Electronic Information – including information beyond that required for the payment of the tax such as returns, statements, reports, notifications and applications- “in a form or manner approved or prescribed by the department.”
- May be great – and the kind of thing you would have seen me pushing for when I was Director of Tax, bringing the Division into the 21st century

12. Other Admin – Information Management System

- It may be information the taxpayer have already – but it may not be in our format. Especially for forward looking information, there may be burden on the taxpayer to restate material
- Do we miss underlying changes because we force financial data into our world view as defined by our forms?

12. Other Admin; Interest (AS 43.55.020 (g))

- Note: Concerns about interest in Dr. van Meurs' 10/18/07 presentation unfounded.
- IRS interest rules only apply to estimated payments through march 31 – then switch to higher state rate found in as 43.05.225 (11%)

13. Cook Inlet Simplicity

- Suggest Cook Inlet Ceilings could be implemented more simply.
  Current statutory language historical product
  - Currently calculations have to be done individually for each lease or property, (twice if produces gas and oil)
  - Could be done Once for Cook Inlet
  - Regulations imported into Statute

13. Cook Inlet Simplicity

- Two rules –
- (1) Ceilings - Cook Inlet oil remain zero and gas taxes preserve 2005-2006 gas prices, tax rates and ELF (volumes are actual) until 2022
- (2) Because Ceilings were meant to benefit consumers, not producers, any pertinent credits and losses that would have been needed to reduce CI taxes to ceilings cannot be applied elsewhere – Taxpayer doesn't get benefits of credits and ceilings.

13. Cook Inlet Simplicity

- CI Tax without ceilings or credits: $10
- Apply "CI Credits" (5)
- Tax after Credits 5

- Ceiling $3

- Taxpayer cannot pay $3 in tax, and then try to sell $5 credit

14. Effective Date

- Generally Effective January 1, 2008
  - Two good tax policies
  - change corresponded to tax year
  - Limited retroactivity
    - Corrosion provisions retroactive.

Senate Resources Committee SB 2001 Context

Presentation by Dan E. Dickinson, CPA
For Legislative Budget & Audit Committee
October 22, 2007

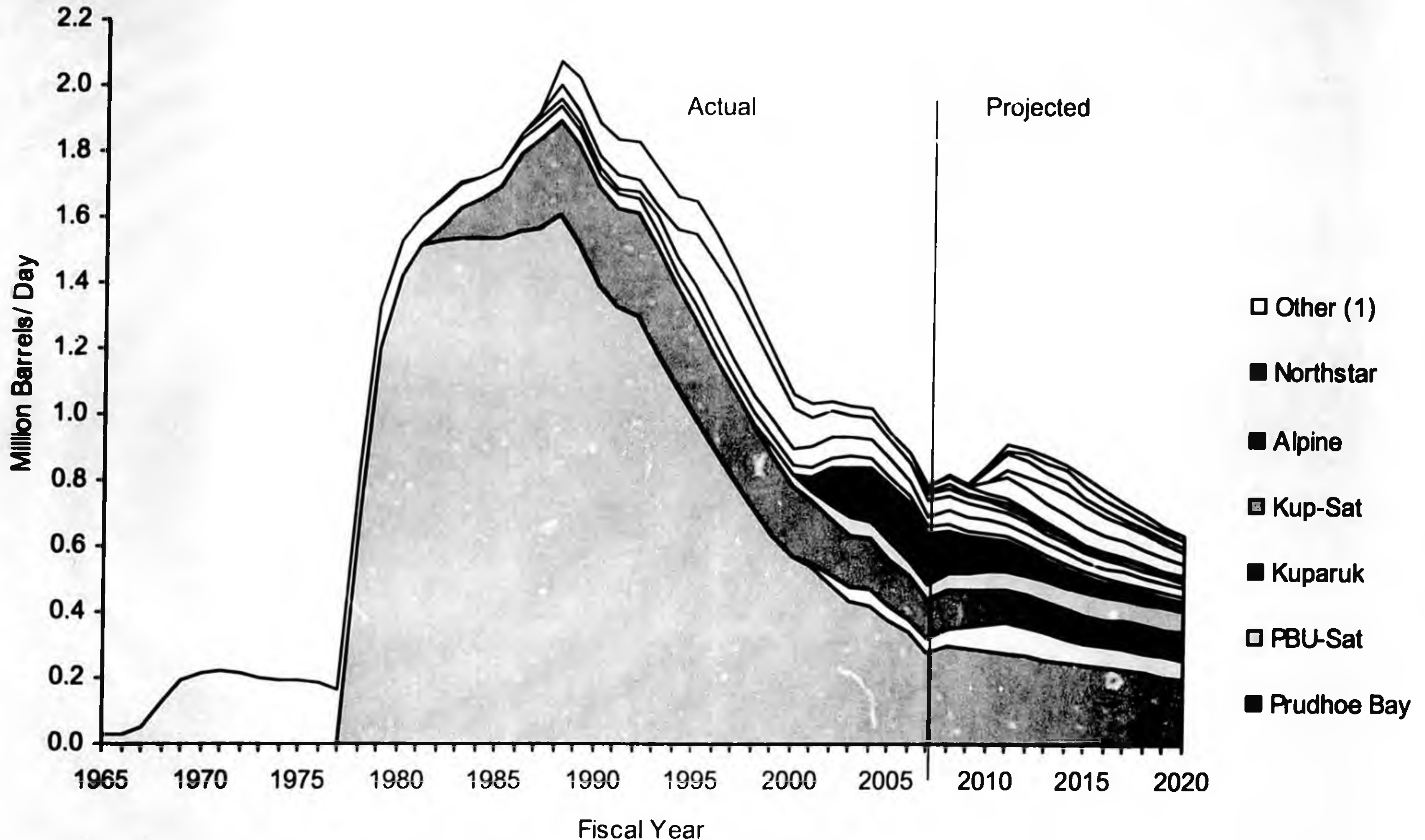
Outline

- Part I: Context - Observations from 30,000 feet
  - Clear tax rules are better than an approval process in front of a government agency
  - Broad and Robust rules applied to everyone better than a narrow rule applied to a single or few (known) taxpayers
  - Windfall Profits can be an effective taxing tool
  - Information informs judgments
- Part II: Detail – applies these conclusions to SB 2001, section by section.

What’s going on?

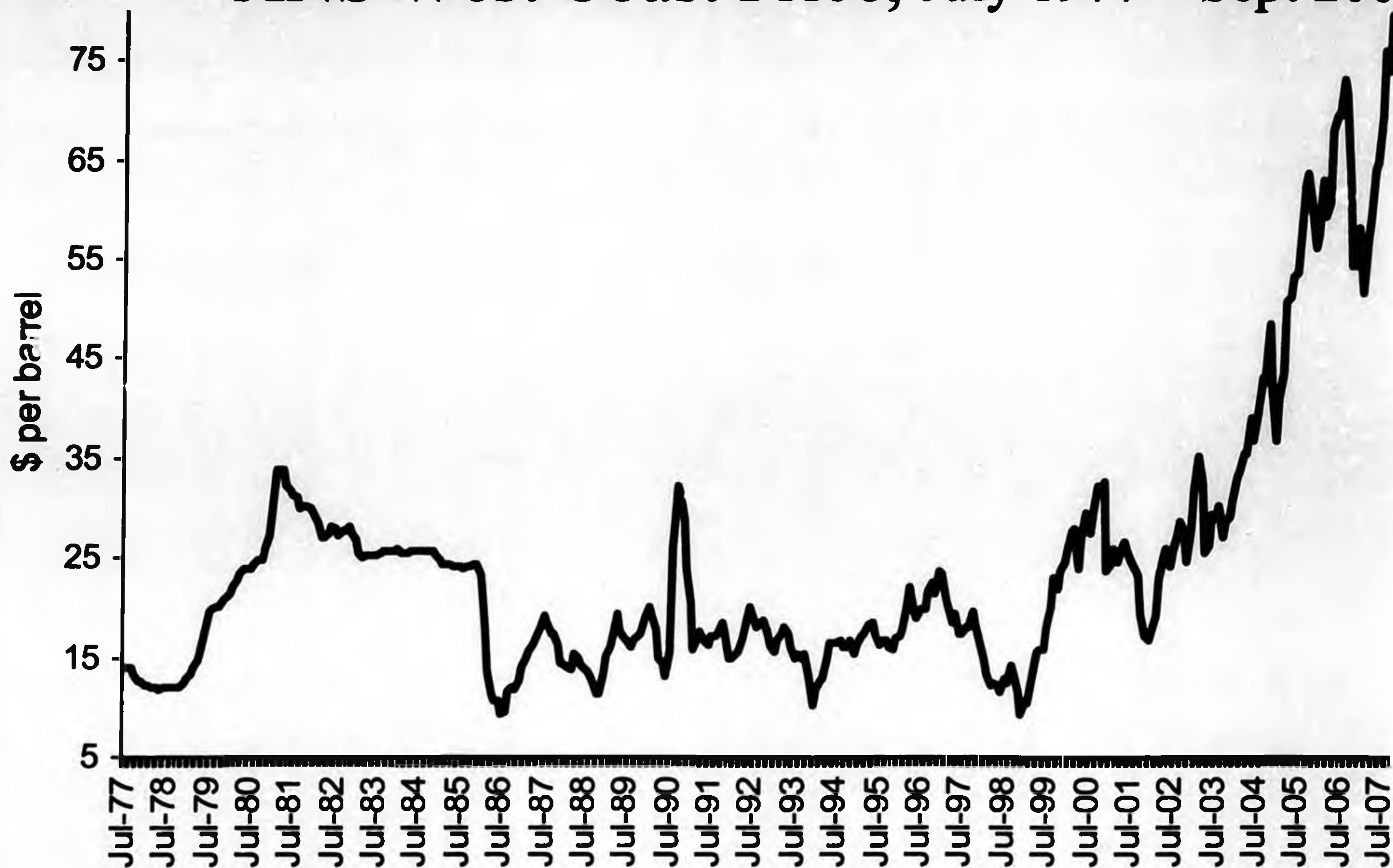
- Is this a discussion of tax – or is trying to “initiate a bidding round.”
- Is this a commercial discussion with partners or is it a debate on fiscal policy?

Alaska Oil Production, 1965 - 2020



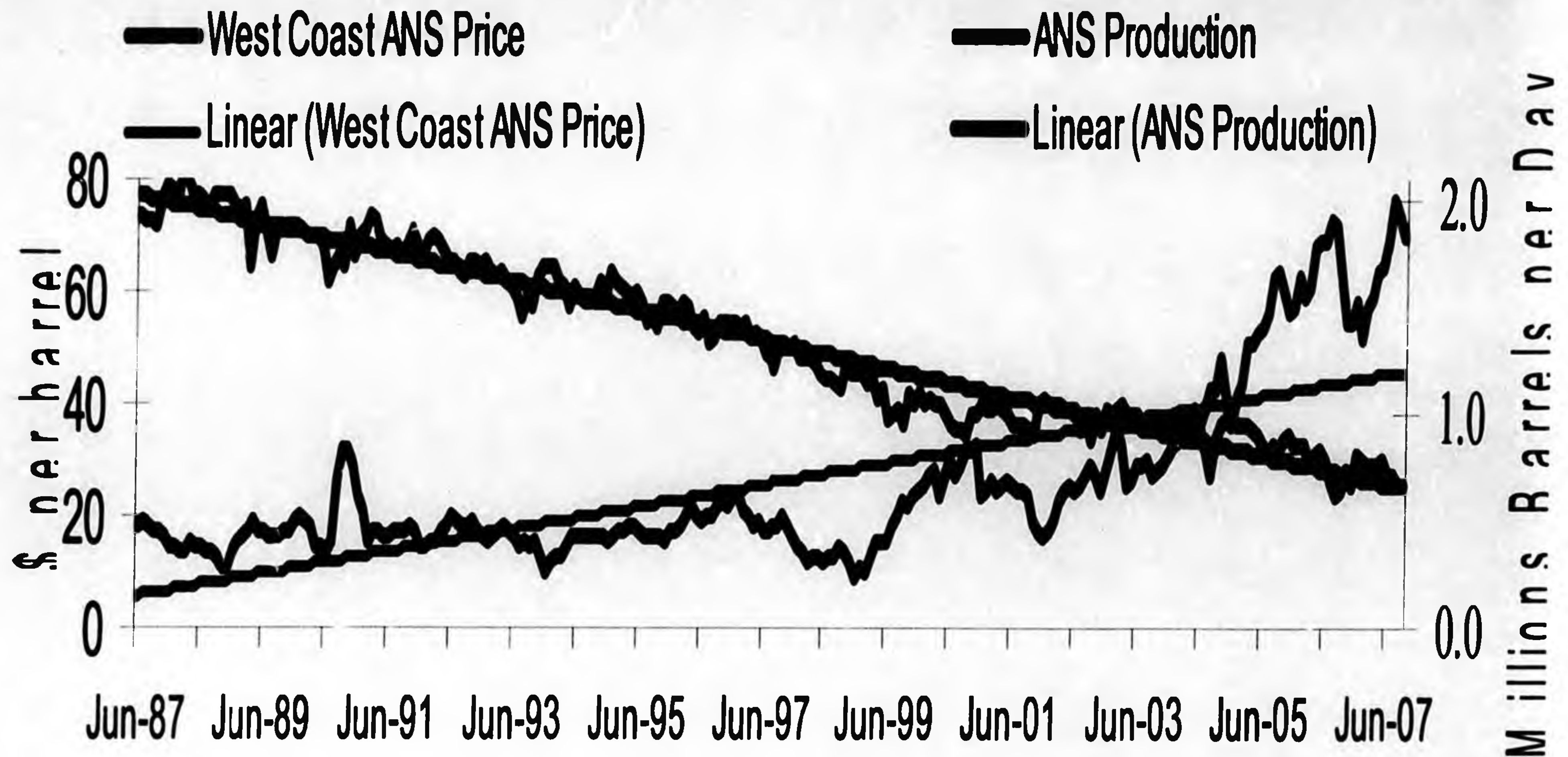
Source: Alaska Department of Revenue, Fall 2006 Revenue Sources Book. extrapolated

(1) Cook Inlet, Duck Island, Milne Point, Greater Point McIntyre, Liberty, Known On & Offshore, Fiord and NPRA.



Source: Alaska Department of Revenue, Tax Division

ANS West Coast Price and Oil Production



Source: Alaska Department of Revenue, Tax Division

Production vs. Price

- 2 million barrels a day at $15 = $30 million
- .7 million barrels a day at $80= $56 million

- .7 million barrels a day at $15 = $10 million

Alaska Constitution

- **Article 1 - Declaration of Rights**
- **§ 1. Inherent Rights**
- This constitution is dedicated to the principles that all persons have a natural right to life, liberty, the pursuit of happiness, and the enjoyment of the rewards of their own industry; that all persons are equal and entitled to equal rights, opportunities, and protection under the law; and that <u>all persons have corresponding obligations to the people and to the State.</u>

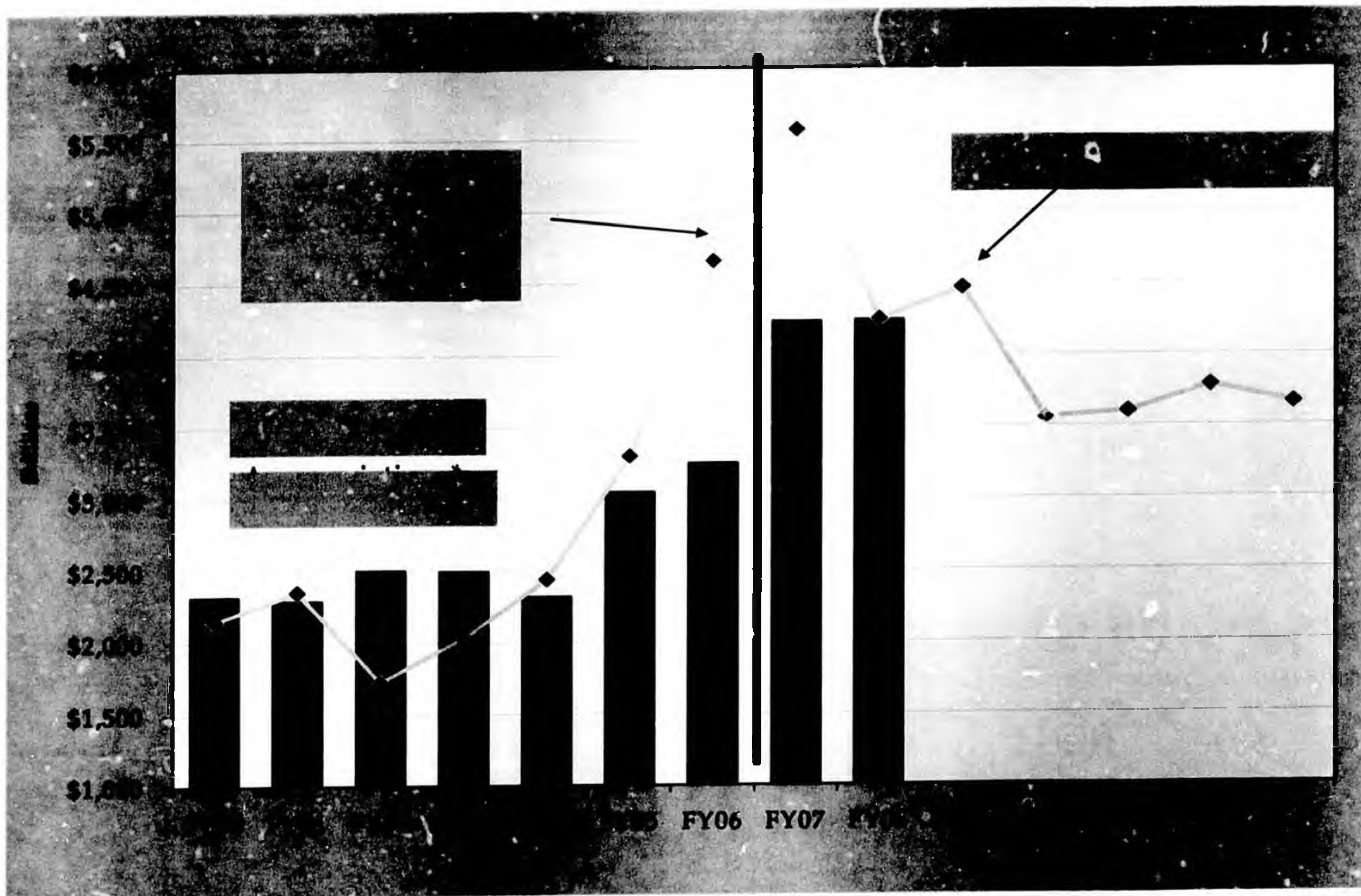
- Moving beyond the idea of taxes as a set of mutual obligations within a society – and focusing on 'leaving money on the table.'
  - For a tax - rules are better than seeking approvals from regulatory agencies.
  - For a tax - broad and robust rules are better than narrow rules that affect one or a few (known) taxpayers.

- What is the right level of tax?
  - If you believe that there are windfall profits that should be accruing to the government (the people) and not oil companies – then there should be a windfall profits tax.
  - If you believe this is just another commercial arrangement and only chumps take a net, then our piece should be a piece of the gross.

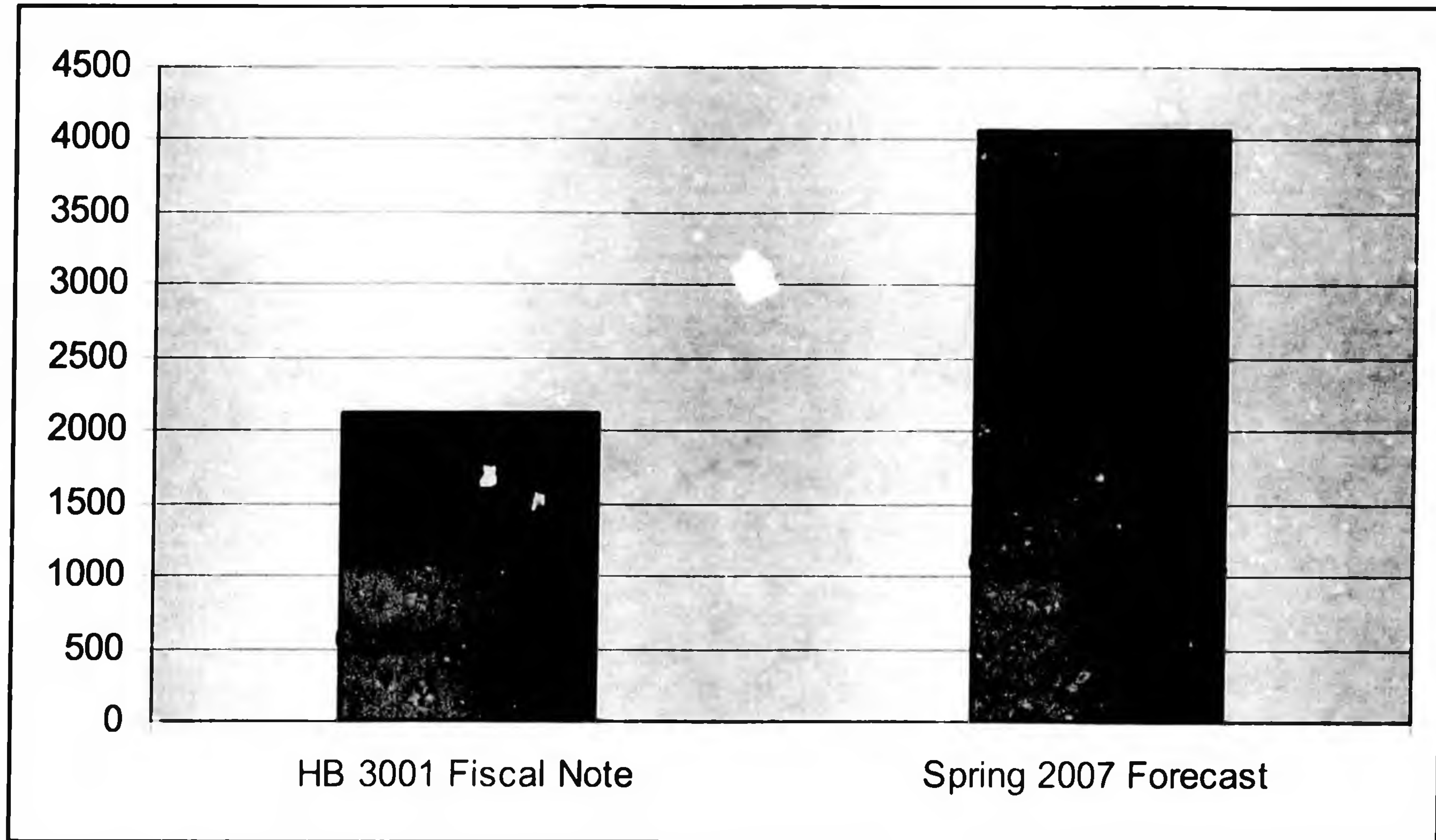
Taxation is said to be an absolute power… and like sovereign power of every other description, is trusted to the discretion of those who use it.

Chief Justice Marshal in McCulloch v Maryland (1819)

Increasing Costs



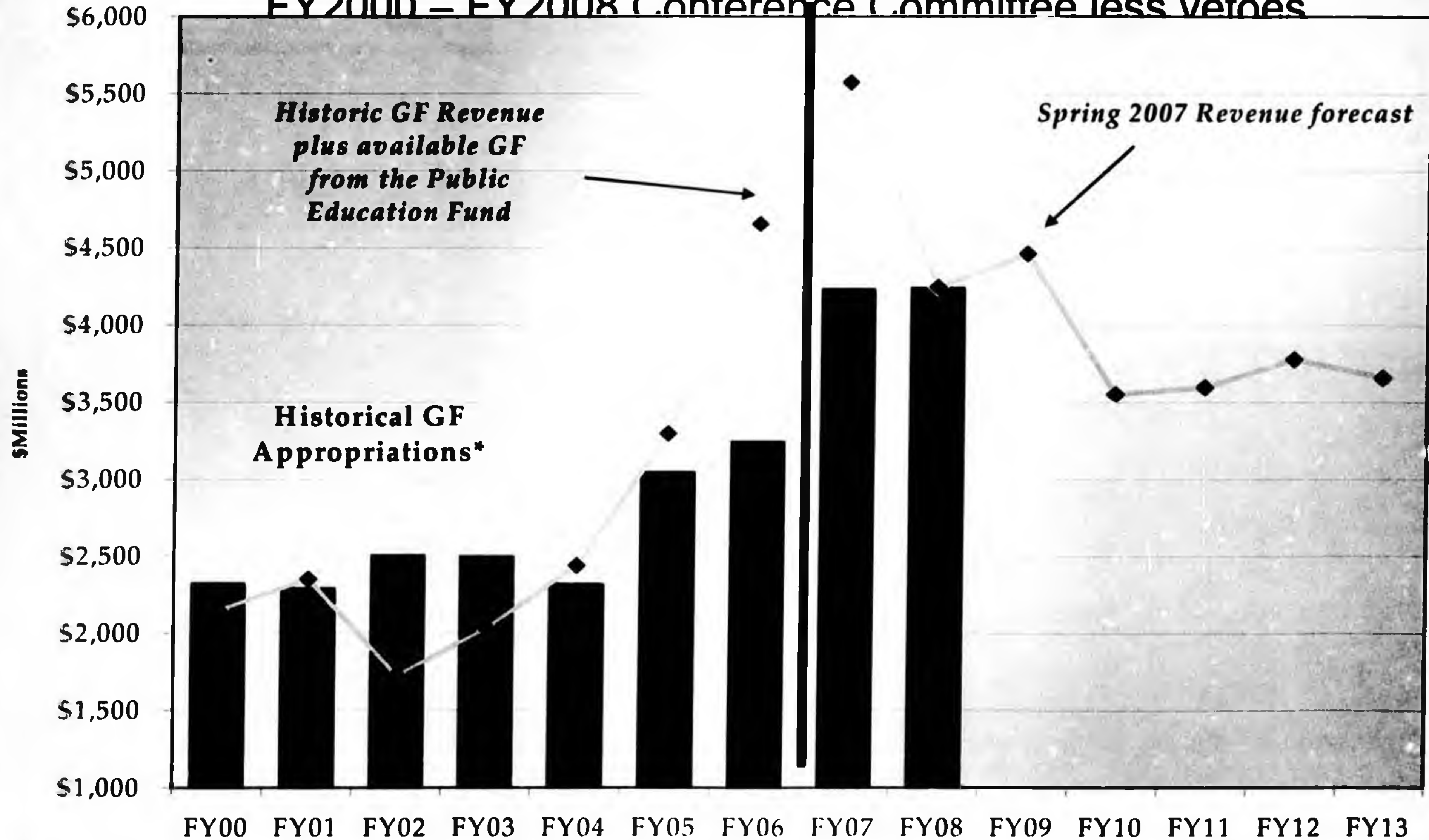
FY 2007 Operating Cost Assumption ($millions)



Source: DOR August 3, 2007 report

General Fund Revenue including Public Education Fund versus Appropriations*

FY2000 – FY2008 Conference Committee less vetoes

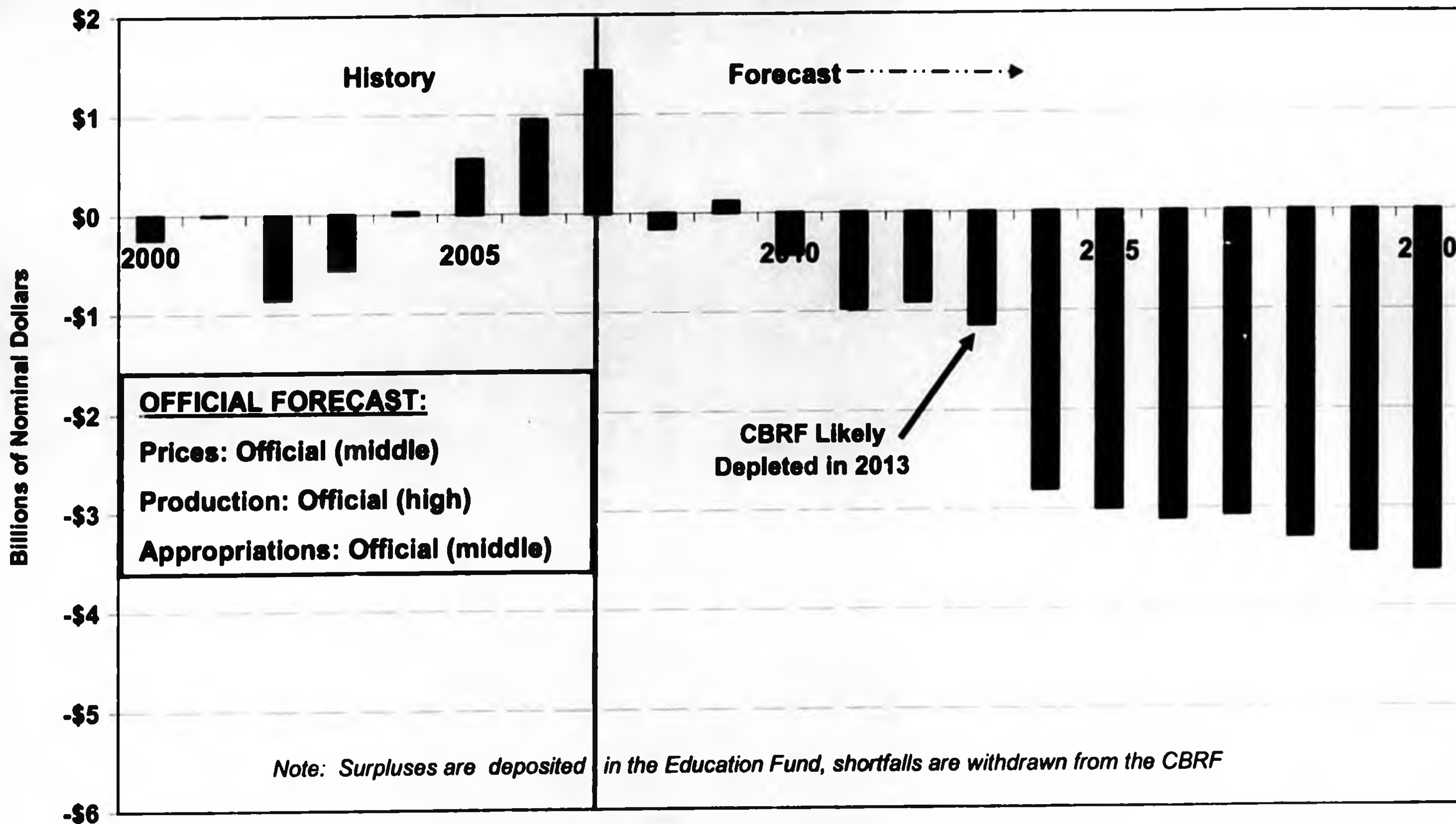


*Excludes appropriations to Public education Fund and some other savings accounts. For example, FY07 excludes $1.000 appropriation to Public Education Fund, $182.7 million appropriation to Power Cost Equalization Endowment, $50.0 million to CBR and estimated $104.7 appropriation to the Alaska Capital Income Fund.

Source: Office of Management and Budget and Alaska Department of Revenue Spring 2007 Revenue Sources Book.

Historical and Forecasted Budget Surpluses and Deficits
FY 2000 to FY 2020

assumes official revenue forecast (official prices, official production) and budget appropriations growth of 2.5%



Information

- Information informs and helps with judgments - But it doesn't usually "speak for itself":
- What would have happened differently in FY 2007 with better information?

FY 2007 first snapshot

FY 2007 - All figures in millions of dollars	Regular Session - May 2006
TOTAL GF REVENUE:	
Oil and Gas Property Tax	36.7
Oil and Gas Income Tax	479.2
Oil and Gas Production Tax	959.8
Oil and Gas Hazadous Release	7.8
Oil and Gas Royalties	1,524.9
Total Oil & Gas	3,008.4
Non oil and gas: All other Taxes, Charges, fines & Forfeitures, Rents, non oil and gas Royalties, Investment Revenues	428.3
Total GF Revenue	3,436.7
Forward funding of Education used in current year:	
TOTAL GF Appropriations/Authorizations:	3,209.1
SURPLUS	227.6

Source: Leg Finance and DOR Spring 2006 RSB; average forecast price$53.60

FY 2007 second snapshot

FY 2007 - All figures in millions of dollars	Regular Session - May 2006	PPT	Special Session Aug 2006
TOTAL GF REVENUE:			
Oil and Gas Property Tax	36.7		36.7
Oil and Gas Income Tax	479.2		479.2
Oil and Gas Production Tax	959.8	1,343.0	2,302.8
Oil and Gas Hazadous Release	7.8		7.8
Oil and Gas Royalties	1,524.9		1,524.9
Total Oil & Gas	3,008.4		4,351.4
Non oil and gas: All other Taxes, Charges, fines & Forfeitures, Rents, non oil and gas Royalties, Investment Revenues	428.3		428.3
Total GF Revenue	3,436.7	1,343.0	4,779.7
Forward funding of Education used in current year:			
TOTAL GF Appropriations/Authorizations:	3,209.1		3,493.6
SURPLUS	227.6		1,286.1
Note: FY 2006 PPT payment in 2007		420.0	
FY 2007 payments in 2006:		923.0	
		1,343.0	

FY 2007 third snapshot

FY 2007 - All figures in millions of dollars	Regular Session - May 2006	Special Session Aug 2006	Spring Forecast 2007	Rec to Leg Fin 2007
TOTAL GF REVENUE:				
Oil and Gas Property Tax	36.7	36.7	52.0	
Oil and Gas Income Tax	479.2	479.2	565.1	
Oil and Gas Production Tax	959.8	2,302.8	2,114.2	
Oil and Gas Hazadous Release	7.8	7.8	10.4	
Oil and Gas Royalties	1,524.9	1,524.9	1,583.0	
Total Oil & Gas	3,008.4	4,351.4	4,324.7	
Non oil and gas: All other Taxes, Charges, fines & Forfeitures, Rents, non oil and gas Royalties, Investment Revenues	428.3	428.3	655.5	
Total GF Revenue	3,436.7	4,779.7	4,980.2	
Forward funding to Public Education Fund used in current year:				572.9
Total:				5,553.1
TOTAL GF Appropriations/Authorizations:	3,209.1	3,493.6	4,980.2	
Forward funding to Public Education Fund used in current year:				572.9
Total:				5,553.10
SURPLUS	227.6	1,286.1	-	
NB: CBRF:	20.0		70.0	

FY 2007 comparisons

FY 2007 - All figures in millions of dollars	Special Session Aug 2006	Spring Forecast 2007	difference	%
TOTAL GF REVENUE:				
Oil and Gas Property Tax	36.7	52.0	15.30	42%
Oil and Gas Income Tax	479.2	565.1	85.90	18%
Oil and Gas Production Tax	2,302.8	2,114.2	(188.60)	-8%
Oil and Gas Hazadous Release	7.8	10.4	2.60	33%
Oil and Gas Royalties	1,524.9	1,583.0	58.10	4%
Total Oil & Gas	4,351.4	4,324.7	(26.70)	-1%
Non oil and gas: All other Taxes, Charges, fines & Forfeitures, Rents, non oil and gas Royalties, Investment Revenues	428.3	655.5	227.20	53%
Total GF Revenue	4,779.7	4,980.2	200.50	4%

Information

- When and how would a 'better' forecast have made a difference?
- When and how would closer monitoring have made a difference?
- Separate debate about regulatory control issues – but that is different from the fiscal debate.
- Separate issue about long term policy

One way to use the information:

Simple Model of FY 2008 Production Tax Revenue to match Administrations Sept 4th Handouts:

Price Scenarios on Sept 4 Handout	Annual Volumes (w/o royalty)	Total Destination Value of non Royalty Barrels	Less Downstream costs from RSB	Less Upstream costs (capex and opex) from RSB	Resulting Production Tax Value	Tax Rate	Base Tax Calculation at 22.5% and 25% and difference	Per Barrel Production Tax Value	Adjustment for Price Index Calculation	Price Index	Progressivity Rate per Price Index Dollar	Resulting progressivity rate	Progressivity Tax = Rate times value	Total Tax before credits	TIE Credits (Transitional Investment Expenditures)	Capital Costs * 20% or 10%	Tax net of credits	Tax per Price Scenarios on Sept 4 Handout	Unaccounted for in this simple model	Unaccounted for in this simple model (%)
						Base Tax		Progressivity							Credits					
$/bbl	MM bbls	MM $	MM $	MM $	MM $	%	MM $	$/bbl	$/bbl	$/bbl	%	%	MM $	MM $	MM $	MM $	MM $	MM $	MM $	%
A	B	C= (A * B)	D	E	F= (C+D+E)	G	H= (F*G)	I= (F/B)	J	K= (I-J)	L	M= (K*L)	N= (M*F)	O= (H+N)	P= (Q/2)	Q=	R= (O+P+Q)	S	T (S-R)	U= (T/S)
Under Current Law																Total Cost:				
		Per bbl:	(7.22)													1,900.0				
30	244	7,320	(1,762)	(4,058)	1,500	22.5%	337.6	6.15	40.00					337.6	(190.0)	(380.0)	-	-		
40	244	9,760	(1,762)	(4,058)	3,940	22.5%	886.6	16.15	40.00					886.6	(190.0)	(380.0)	316.6	200	(116.6)	-58%
50	244	12,200	(1,762)	(4,058)	6,380	22.5%	1,435.6	26.15	40.00					1,435.6	(190.0)	(380.0)	865.6	700	(165.6)	-24%
60	244	14,640	(1,762)	(4,058)	8,820	22.5%	1,984.6	36.15	40.00					1,984.6	(190.0)	(380.0)	1,414.6	1,300	(114.6)	-9%
70	244	17,080	(1,762)	(4,058)	11,260	22.5%	2,533.6	46.15	40.00	6.15	0.25%	1.54%	173.1	2,706.7	(190.0)	(380.0)	2,136.7	2,000	(136.7)	-7%
80	244	19,520	(1,762)	(4,058)	13,701	22.5%	3,082.6	56.15	40.00	16.15	0.25%	4.04%	553.1	3,635.7	(190.0)	(380.0)	3,065.7			
Under Changes indicated in Sept 4th Handouts																				
30						25.0%	375.1	6.15	30.00					375.1		(190.0)	185.1	200	14.9	7%
40						25.0%	985.1	16.15	30.00					985.1		(190.0)	795.1	800	4.9	1%
50						25.0%	1,595.1	26.15	30.00					1,595.1		(190.0)	1,405.1	1,300	(105.1)	-8%
60						25.0%	2,205.1	36.15	30.00	6.15	0.20%	1.23%	108.5	2,313.6		(190.0)	2,123.6	2,000	(123.6)	-6%
70						25.0%	2,815.1	46.15	30.00	16.15	0.20%	3.23%	363.7	3,178.8		(190.0)	2,988.8	2,900	(88.8)	-3%
80						25.0%	3,425.1	56.15	30.00	26.15	0.20%	5.23%	716.5	4,141.6		(190.0)	3,951.6			
Incremental Change: Proposal less Current Law																				
30							37.5							37.5	190.0	190.0	185.1	200	14.9	7%
40							98.5							98.5	190.0	190.0	478.5	600	121.5	20%
50							159.5							159.5	190.0	190.0	539.5	600	60.5	10%
60							220.5		(10.00)	6.15		1.23%	108.5	329.0	190.0	190.0	709.0	700	(9.0)	-1%
70							281.5		(10.00)	10.00		1.69%	190.6	472.1	190.0	190.0	852.1	900	47.9	5%
80							342.5		(10.00)	10.00		1.19%	163.4	505.9	190.0	190.0	885.9			

Work To Date

- **<u>Summary</u>** Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law (2 pages dated 10/8/07)
- **<u>Detail</u>** Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law (6 pages dated 10/8/07)
- <u>Preliminary estimate of the FY 2008 revenue effects of four changes proposed by Governor Sarah Palin to the oil and gas production tax as 43.55 ON Sept 4, 2007 and October 1, 2007</u> (October 3, 2007)
- Sectional Analysis (with Steve Porter) On October 1 work draft, and supplemental analysis on SB/HB 2001

Part II -detail

Looking for places where

- tax rules are replaced by the discretion of an agency (or vice versa)
- Broad and robust rules are replaced with narrow specific approaches.
- might make production tax, or features of it look more or less like a windfall profits tax
- Data might not yield hoped for information

REPORT TO THE ALASKA STATE LEGISLATURE

on the

PRELIMINARY ESTIMATE OF THE FY 2008 REVENUE EFFECTS OF FOUR CHANGES PROPOSED BY GOVERNOR SARAH PALIN TO THE OIL AND GAS PRODUCTION TAX, AS 43.55, ON SEPTEMBER 4, 2007 AND OCTOBER 1, 2007

Dan E. Dickinson, CPA, CMA
October 3, 2007

Executive Summary

On September 4, 2007, the Palin Administration proposed changes to Alaska's oil and gas production tax (AS 43.55). Also handed out at that time was a chart demonstrating estimated FY 2008 production tax revenues under different scenarios. That chart showed that at a price level of $70 dollars a barrel, a revenue estimate under current law and cost and volume assumptions to be roughly:

- a billion dollars higher than revenues had the ELF-based tax still been in place; however,
- a billion dollars lower than under current law and summer of 2006 cost and volume assumptions; and
- 800 million dollars lower than under the Governor's plan also using summer of 2006 cost and volume assumptions.

On October 1, 2007, the Administration made public a work draft of a bill incorporating these and other changes. This paper analyzes four of the proposed changes. If implemented for all of FY 2008, these four changes proposed by the Governor would have large and immediate revenue impacts, and in fact account for the 800 million dollar difference identified above:

> The tax rate would go from 22.5 to 25%. At currently predicted volumes and costs, that would generate a revenue increase of about 37.5 million dollars if oil is at $30 a barrel for the entire year and 342.5 million dollars if oil remains at $80 for the entire year.
>
> Progressivity – a mechanism that imposes an additional tax when net values are very high - is changed so that in most circumstances at prices greater than $55 dollars a barrel it will raise up to roughly 190 million more dollars a year than current law. However, because the Administration has opted for the administratively less complex method of calculating progressivity on an annual rather than monthly basis, in cases of short duration spikes in price the proposal may capture fewer dollars.

The TIE (Transitional Investment Expenditure) credits would be eliminated. Those credits allowed producers that are making both current investments, and had been making investments in the period 2000 through 2005, to "supercharge" their current investment credits from 20% to 30%. In FY 2008, eliminating TIE credits will increase revenue by about $190 million a year.

A fourth proposed change will likely have a large revenue impact in its first year but little impact thereafter. It will require capital credits to be taken over two years instead of in the year of investment. If the change were effective July 1, 2007, the State would receive a revenue boost of about 190 million dollars in FY 2008, but would notice little change thereafter.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

Analysis

On September 4, 2007, the Palin Administration proposed 10 changes to Alaska's oil and gas production tax (AS 43.55) summarized in a 150 word handout. Also handed out at that time was a chart handout entitled "FY 2008 Production Tax Estimates." This chart showed FY 08 production tax revenues over a range of oil prices between $30 and $70 using the four following sets of assumptions:

(a) Current law and production and cost assumptions;
(b) Current law using production and cost assumptions from the summer of 2006;
(c) The Governor's proposed changes; and,
(d) The ELF-based tax as though it were still in place.

At a price level of $70 dollars a barrel[1], the revenue estimate shown under current law and assumptions is roughly:

- A billion dollars higher than revenues had the ELF-based tax still been in place; however,
- A billion dollars lower than under current law and summer of 2006 cost and volume assumptions; and
- 800 million dollars lower than under the Governor's plan also using summer of 2006 cost and volume assumptions.

On October 1, 2007, the Administration made a work draft of a bill public. This paper analyzes four of the proposed changes from that bill. Using a very simple one page model (Attachment One), the Governor's proposed changes are compared with existing law using the same cost and volume assumptions. If implemented for all of FY 2008, these four changes proposed by the Governor have large and immediate revenue impacts, and, in fact, account for the 800 million dollar difference identified above between current law and the proposal. The four changes are:

A change in tax rate on net profits from 22.5% to 25%;
Two of the three changes proposed for the method of calculating progressivity;
Elimination of the TIE credit, and
Requiring taxpayers to take investment credits over two years.

On September 4, 2007, when the chart was released the Commissioner of DOR stated that he did not know when the bill would become effective. However the analysis that

[1] Although on September 4, 2007, the ANS price was in the mid seventies, according to archival price data at DOR's website, it had been 70.76 as recently as August 22 (Site accessed October 2, 2007:
http://www.tax.state.ak.us/programs/oil/prices/monthlydata/2007/Aug07.xls

best fits the September 4 handouts, and that is presented in this paper is driven by a July 1, 2007, effective date. The work draft of the bill, however, has proposed a January 1, 2008, effective date. Using the effective dates in the Governor's proposed legislation would cut the 800 million difference for FY 2008 roughly in half to $400 million.

"25% Tax Rate on Net Profits"

AS 43.55.011(e) levies a tax of 22.5% on the "production tax value of the taxable oil and gas." The proposed change found in sections 15 and 17 of the October 1, 2007, work draft modifies AS 43.55.011(e) and (g) to up that figure by an additional 2.5% to 25%. The effect of this change on 2008 revenues is modeled on the table below.

Simple Model of FY 2008 Production Tax Revenue: Base Rate

Price Scenarios on Sept 4 Handout	Annual Volumes (w/o royalty)	Total Destination Value of non Royalty Barrels	Less Downstream costs from RSB	Less Upstream costs (capex and opex) from RSB	Resulting Production Tax Value	Tax Rate	Base Tax Calculation at 22.5% and 25% and difference
$/bbl	MM bbls	MM $	MM $	MM $	MM $	%	MM $
A	B	C= (A * B)	D	E	F= (C+D+E)	G	H= (F*G)
Under Current Law							
			7.22 per bbl				
30	244	7,320	(1,762)	(4,058)	1,500	22.5%	337.6
40	244	9,760	(1,762)	(4,058)	3,940	22.5%	886.6
50	244	12,200	(1,762)	(4,058)	6,380	22.5%	1,435.6
60	244	14,640	(1,762)	(4,058)	8,820	22.5%	1,984.6
70	244	17,080	(1,762)	(4,058)	11,260	22.5%	2,533.6
80	244	19,520	(1,762)	(4,058)	13,701	22.5%	3,082.6
Under Changes Indicated in Sept 4th handouts							
30						25.0%	375.1
40						25.0%	985.1
50						25.0%	1,595.1
60						25.0%	2,205.1
70						25.0%	2,815.1
80						25.0%	3,425.1
Incremental Change: Proposal less Current Law							
30							37.5
40							98.5
50							159.5
60							220.5
70							281.5
80							342.5

The format of this table will be repeated several times in this report excerpting columns from the entire table which can be found as Attachment One. The table is divided into three horizontal sections. Within each section the analysis is shown at prices that range from $20 a barrel up to the today's price of $80. (Note – when comparisons are made to the Governor's chart, the analysis uses the Administration's assumptions and only goes up to $70.) The first section is based on current law. Below it, the second section is based on the Governor's September 4, 2007, proposals. Finally, the third section is just the difference between the first two sections – the incremental dollar effect of implementing the change.

Columns A through F are identical whether under current law or the proposed changes.[2] The first, column A, is the destination value. The next column has taxable barrels based on the volumes found in the Department of Revenue's spring 2007 Revenue Sources Book (RSB). Column C is the product of the first two. In the next two columns, costs also found in the RSB are deducted. In column D, downstream costs are quoted at $7.22 a barrel, which must be multiplied by volumes, while upstream costs are given as total dollars in column E. Finally, costs are subtracted to arrive at the "production tax value" shown in column F.

Starting with column G, the section under current law and the section describing the effect of the proposals are different. Current law multiplies "production tax value" times 22.5%, while in the second section the Governor's proposed rate of 25% is used. The "Incremental Change" portion of Column H shows the annual difference this proposed change would make at this year's production levels and it ranges from $37 million at the $30 per barrel price level to just under 10 times that or roughly $342.5 million dollars at the $80 price level seen today.

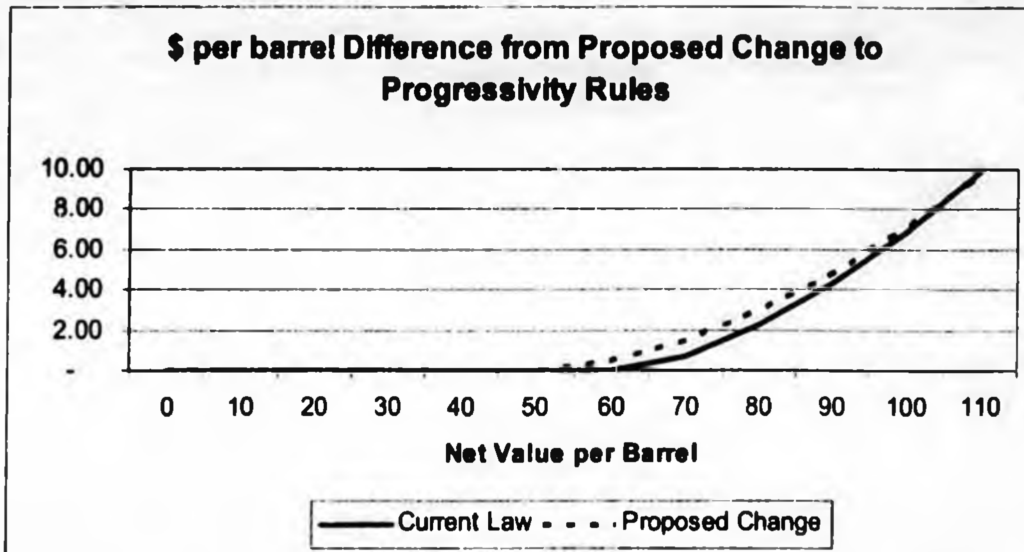
"Progressive Feature that Kicks In at $30 Net Value (annual) and rises at Two-tenths of a Percent per Dollar"

This proposal incorporates three changes to the progressivity feature of which two are incorporated into this model. Under current law, AS 43.55.011(g) and (h), the progressive feature is calculated as an additional tax of two and a half tenths of a percent for every dollar per barrel of net value over the $40 price index starting point. This proposal, found in sections 17 and 18 of the October 1 work draft, suggests the progressive feature should be calculated as an additional tax of two tenths of a percent for every dollar per barrel of net value over a $30 price index starting point.

[2] That is, they are identical in this simple model. The Governor has also proposed some smaller changes described below that would affect the total deductible costs as well; however, they have not been modeled here.

	Current Law	Proposed Change
Price Index starting point	$40 per barrel	$30 per barrel
Rate per $ in Price Index	.25%	.20%

Put more plainly, under the proposal, progressivity will start at lower per barrel values than under current law. However, once it starts, progressivity will rise more slowly. Until the net production tax value reaches $80 dollars a barrel, the Administration's suggested change to these two parameters will consistently produce more progressivity dollars than the current statute. At a net of $80, the suggested changes and current law will yield the same result.[3] At net values above $80, the formula in current law will produce more progressivity dollars.[4] However, under both the current statute and the Governor's proposal, the total tax rate progressivity is capped at 25% - which occurs at an even higher price.



As might be expected at today's high prices, changes to progressivity are an important part of calculating the overall tax burden and the difference between current law and this proposal. The table on the next page illustrates the dollar effect of these two changes in FY 2008.

This table has the same format as the table described on pages 4 and 5 above -- the table is divided into three horizontal sections for current law, the September 4, 2007, proposals, and, the difference between those two. Within each section the analysis is

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[3] Because (80 - 30)*.002 = (80 – 40) *.0025 for those who care about the algebra.

[4] To translate $80 net value into WC market prices total RSB costs of $23.85 per barrel need to be added meaning the cross over point would be about $103.85, roughly 20% higher than current prices.

shown at prices that range from $20 a barrel up to the today's price of $80. The computations to reach column F are not reproduced.

Column I converts the column F production tax value back to dollars per barrel by dividing column F dollars by the barrels in column B. Column J shows the starting point for the Price Index as $40 under current law and $30 under the Governor's proposal. In Column K, the price index is calculated by subtracting J from I. In Column L, the current and proposed progressivity rates per dollar of price factor are shown as .0025% and .002% respectively. In column M, these are multiplied by the price index to yield the new progressivity rate. Finally, in column N, the dollars of progressivity are calculated by multiplying the column M rate by the same base that was subject to taxation found in column F.

Simple Model of FY 2008 Production Tax Revenue: Progressivity

Price Scenarios on Sept 4 Handout	Annual Volumes (w/o royalty)	MEMO: Resulting Production Tax Value	Per Barrel Production Tax Value	Adjustment for Price Index Calculation	Price Index	Progressivity Rate per Price Index Dollar	Resulting progressivity rate	Progressivity Tax = Rate Times Value
$/bbl	MM bbls	MM $	$/bbl	$/bbl	$/bbl	%	%	MM $
A	B	F= (C+D+E)	I= (F/B)	J	K= (I-J)	L	M (L*K)	N= (M*F)
Under Current Law								
30	244	1,500	$ 6.15	40.0				
40	244	3,940	$ 16.15	40.0				
50	244	6,380	$ 26.15	40.0				
60	244	8,820	$ 36.15	40.0				
70	244	11,260	$ 46.15	40.0	$ 6.15	0.25%	1.54%	173.1
80	244	13,701	$ 56.15	40.0	$ 16.15	0.25%	4.04%	553.1
Under Changes Indicated in Sept 4th handouts								
30			$ 6.15	30.0				
40			$ 16.15	30.0				
50			$ 26.15	30.0				
60			$ 36.15	30.0	$ 6.15	0.20%	1.23%	108.5
70			$ 46.15	30.0	$ 16.15	0.20%	3.23%	363.7
80			$ 56.15	30.0	$ 26.15	0.20%	5.23%	716.5
Incremental Change: Proposal less Current Law								
30								
40								
50								
60				(10.0)	$ 6.15		1.23%	108.5
70				(10.0)	$ 10.00		1.69%	190.6
80				(10.0)	$ 10.00		1.19%	163.4

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When just these two elements are considered, the Governor's proposal can be seen to yield between $108.5 and $190.6 million more than the current rules at prices of $60 or above. (With this set of inputs the maximum difference is close to $190.6 million.)

However, what these two elements take in higher revenues, a third part of this proposed change may more than give back. To many people in the Legislature in 2006, the purpose of the progressivity was to capture a premium when there were price spikes. Therefore, current law requires the analysis to be done on a monthly basis. (Although now as daily prices hover around the $80 per barrel level it may seem quaint; but in the summer of 2006 as the current law was being crafted, prices were surpassing $70 a barrel for the first time and to many that seemed like a spike.) The Administration's proposal would be administratively simpler requiring only an annual analysis. However, this change might reduce taxes by hundreds of millions of dollars.

Consider the price spike preceding the first Gulf War when prices doubled between July and September 1991, and then soon returned to where they had been. The following table illustrates what might happen should FY 2008 have just such a spike in it:

Comparing Annual and Monthly analysis of FY 2008 with hypothetical spike

	US West Coast Price/ bbl	Per Barrel Total Costs	Per Barrel Production Tax Value	Adjustment Converting Production Tax Value to Price Index	Price Index	Rate per Dollar of Price Factor	Incre-mental Progres-sivity %	Volumes (millions of bbls)	Progres-sivity Tax (millions of dollars)
	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	%	%	MM bbls	MM $
A	B	C	D= (B+C)	E	F= (D+E)	G	H= (F*G)	I	J= (D*H*I)
Monthly Analysis, $40 Adjustment and .0025% Parameter under Current Law									
Jul	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Aug	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Sep	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
Oct	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Nov	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
Dec	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Jan	77.15	(23.85)	53.29	(40.00)	13.29	0.25%	3.32%	20.7	36.7
Feb	102.86	(23.85)	79.01	(40.00)	39.01	0.25%	9.75%	18.7	144.2
Mar	77.15	(23.65)	53.29	(40.00)	13.29	0.25%	3.32%	20.7	36.7
Apr	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
May	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Jun	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
								244.0	217.6
Yearly Analysis, $30 Adjustment and .002% Parameter, as Proposed									
Yr	60.00	(23.85)	36.15	(30.00)	6.15	0.20%	1.23%	244.0	108.5

In the simple model presented on page 7, no progressivity dollars were generated under current law at the $60 scenario level. Implicit in the model is that the price stays flat at $60 all year. But, in the model presented on page 8, instead of a flat $60, the price hovers around $51.43 for most of the year except for a three month spike[5]. In this hypothetical spike, like in 1991, prices will double over two months and then fall back. The $51.43 was chosen so that the year's price would average out to $60 -- and the point would be dramatically illustrated. Under this scenario, the current law would generate $217.6 million of progressivity over the year – just about twice what would be generated under the rules the Governor is proposing. (The $108.5 figure under the Administration's plan can be found in both the tables on page 7 and 8.)

Please note the table on page 8 is not a forecast but an illustration!!! If prices stay relatively flat, incorporating the kind of variation seen in most 12 month periods, the Governor's proposal will produce more progressivity dollars than current law. However, it will not necessarily catch a single peak or spike. Incidentally, as might be expected, if the Governor's two suggested parameter changes are combined with a monthly analysis, then a spike such as that illustrated in the table on page 8 brings in significantly more revenue than current law.

"Eliminates the Transitional Investment Expenditures (TIE) Credits"

The Transitional Investment Expenditures (TIE) credit, AS 43.55.023 (i), was transformed in the Legislative process. As originally introduced by the Murkowski Administration, it permitted capital costs incurred in the prior five years to be used as additional capital credits through 2013 with certain restrictions. The Legislature transformed the idea and required new matching investment before the TIE credits would be allowed. If a producer were in harvest mode and not making any new investments, the TIE would be of no use, whereas a producer that increased its investment by about 40% could take full advantage of the TIE credit. The law allowed certain producers with a good history of investment to "supercharge" their new investments made between 2006 and 2012 and to boost their credit for that investment by an additional 10% from 20% to an effective rate of 30%. To take advantage of this 10% credit, a producer had to have two things – prior investment and current investment. The credit would have expired in 2013 on its own. The Palin Administration, in section 63 of the October 1, 2007, work draft, proposes ending it sooner – December 31, 2007 -- which means that TIE credits would still be allowed for half of FY 2008. However, for simple modeling purposes to best match the Administration's September 4, 2007, model, the elimination of the TIE credit is shown for the entire year.

The simple model incorporates the following assumptions. In its August 3, 2007, Petroleum Profits Tax (PPT) Implementation Status Report, the DOR estimates that $1.9

[5] Of all the places in the future to place the spoke, February was chosen with only 29 days of production in FY 2008 to model a conservative scenario.

billion in capital costs will be reported for FY 2008. The model further assumed that in the second year of the TIE program, every dollar invested in FY 2008 still has a match from prior years' investments – that is, all the investment was supercharged from 20% to 30%. Thus, current law allows, and the Governor's proposal will disallow, 10% of $1,900 million or $190 million a year regardless of the price of oil. In the table below, column E is a memo column that shows total upstream costs, columns H and N were calculated in previous tables, and column O sums those results together to generate total tax before credits. In column P, under current law, a credit of 10% of 1.9 billion dollars is taken; no credit is allowed under the Governor's proposal. The final column shows the effect of applying the credit in column P against the tax in column O.

Simple Model of FY 2008 Production Tax Revenue: TIE

Price Scenarios on Sept 4 Handout	MEMO: Less Upstream costs (capex and opex) from RSB	MEMO: Base Tax Calculation at 22.5% and 25% and difference	MEMO: Progressivity Dollars	Total Taxes before credits	TIE Credits	Taxes Due after application of TIE Credit
$/bbl	MM $	MM $	MM $	MM $	MM $	MM $
A	E	H	N	O= (H+N)	P	
Under Current Law						
30	(4,058.0)	337.6		337.6	(190.0)	147.6
40	(4,058.0)	886.6		886.6	(190.0)	696.6
50	(4,058.0)	1,435.6		1,435.6	(190.0)	1,245.6
60	(4,058.0)	1,984.6		1,984.6	(190.0)	1,794.6
70	(4,058.0)	2,533.6	173.1	2,706.7	(190.0)	2,516.7
80	(4,058.0)	3,082.6	553.1	3,635.7	(190.0)	3,445.7
Under Changes Indicated in Sept 4th handouts						
30		375.1		375.1		375.1
40		985.1		985.1		985.1
50		1,595.1		1,595.1		1,595.1
60		2,205.1	108.5	2,313.6		2,313.6
70		2,815.1	363.7	3,178.8		3,178.8
80		3,425.1	716.5	4,141.6		4,141.6
Incremental Change: Proposal less Current Law						
30		37.5		37.5	190.0	227.5
40		98.5		98.5	190.0	288.5
50		159.5		159.5	190.0	349.5
60		220.5	108.5	329.0	190.0	519.0
70		281.5	190.6	472.1	190.0	662.1
80		342.5	163.4	505.9	190.0	695.9

"Requires Capital Expenditure Costs to be Taken as Credits over Two Years Rather than Immediately"

Under current law, AS 43.55.023 (a), capital investment credits may be taken in the year the investment is made. The proposal, found in section 26 of the October 1, 2007, work draft, will require that for a credit generated in year one, only half can be applied in year one and the rest in year two. In DOR Commissioner Galvin's oral presentation September 4, 2007, he stressed that this change was intended to make annual revenues more stable and predictable. There will, however, be immediate one-year revenue implications and the model below assumes the effective date of the change in the law would be timed so as to maximize the revenue effect on FY 2008.

However, this large revenue effect will essentially be limited to one year. In the next year, the total credits allowed will be half of that year's investment and half of the investment made the year after that and so forth each year forward. If investment stays roughly constant, in subsequent years there will be no revenue effect. Thus from the point of view of the State, this appears to create first year savings only. From the taxpayers' point of view, the value of the credits essentially falls by one half year's time value of money.

In the simple model on page 12, columns E, H, N & O are as they were in the TIE table. In column Q, FY 2008 current law will allow 20% of $1,900 or $380 million a year. The Governor's proposal will disallow half of that, 10% of $1,900 or $190 million, and allow the other half. Again, this is regardless of the price of oil. In the final column of the table, this amount is subtracted from the taxes derived in the prior two sections.

This model assumes that the tax and forecasting are on the same basis; but, the world is not that simple. The tax system is based on the calendar year, while the fiscal year (FY) runs from July 1 to June 30. Thus the effect of this change on fiscal year revenues will be split between two fiscal years (FY 2008 and 2009) but thereafter will have little revenue effect.

Simple Model of FY 2008 Production Tax Revenue: Cap Credit

Price Scenarios on Sept 4 Handout	MEMO: Less Upstream costs (capex and opex) from RSB	MEMO: Base Tax Calculation at 22.5% and 25% and difference	MEMO: Progressivity Dollars	Total Taxes before credits	First Year Capital Investment Credit (full or half)	Taxes Due after application of Capital Investment Credit
$/bbl	MM $	MM $	MM $	MM $	MM $	MM $
A	E	H	N	O= (H+N)	Q	
Under Current Law						
					1,900.0	
30	(4,058.0)	337.6		337.6	(380.0)	(42.4)
40	(4,058.0)	886.6		886.6	(380.0)	506.6
50	(4,058.0)	1,435.6		1,435.6	(380.0)	1,055.6
60	(4,058.0)	1,984.6		1,984.6	(380.0)	1,604.6
70	(4,058.0)	2,533.6	173.1	2,706.7	(380.0)	2,326.7
80	(4,058.0)	3,082.6	553.1	3,635.7	(380.0)	3,255.7
Under Changes Indicated in Sept 4th handouts						
30		375.1		375.1	(190.0)	185.1
40		985.1		985.1	(190.0)	795.1
50		1,595.1		1,595.1	(190.0)	1,405.1
60		2,205.1	108.5	2,313.6	(190.0)	2,123.6
70		2,815.1	363.7	3,178.8	(190.0)	2,988.8
80		3,425.1	716.5	4,141.6	(190.0)	3,951.6
Incremental Change: Proposal less Current Law						
30		37.5		37.5	190.0	227.5
40		98.5		98.5	190.0	288.5
50		159.5		159.5	190.0	349.5
60		220.5	108.5	329.0	190.0	519.0
70		281.5	190.6	472.1	190.0	662.1
80		342.5	163.4	505.9	190.0	695.9

The table on the next page sums up the results of the four tables presented previously to show the amount of revenue, and revenue differences, accounted for by this simplistic accounting. Column H and N are summed in column O to show total tax before credits. Columns P and Q are the two credits discussed; and, the final result of applying the credits is seen in Column R.

To determine the Administration's estimates under current law and under the Governor's proposal, figures were simply extrapolated off the September 4, 2007, handout table and these are shown in column S. The sole purpose of making this comparison is to suggest that simplistic models of the four items yield most, but not all, of the revenue differences.

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Simple Models of FY 2008 Production Tax Revenue: Summary

Dollar figures in millions (except when per barrel)

Price Scenarios on Sept 4 Handout	Base Tax Calculation at 22.5% and 25% and difference	Progressivity Tax = Rate times value	Total Tax before credits	TIE Credits (Transitional Investment Expenditures)	Capital Costs * 20% or 10%	Tax net of credits	Tax per Price Scenarios on Sept 4 Handout	Unaccounted for in this simple model	Unaccounted for in this simple model (%)
$/bbl	MM $	MM $	MM $	MM $	MM $	MM $	MM $	MM $	%
A	H= (F*G)	N= (M*F)	O= (H+N)	P= (Q/2)	Q=	R= (O+P+Q)	S	T (S-R)	U= (T/S)
Under Current Law					Total Cost: 1,900.0				
30	337.6		337.6	(190.0)	(380.0)	-	-		
40	886.6		886.6	(190.0)	(380.0)	316.6	200	(116.6)	-58%
50	1,435.6		1,435.6	(190.0)	(380.0)	865.6	700	(165.6)	-24%
60	1,984.6		1,984.6	(190.0)	(380.0)	1,414.6	1,300	(114.6)	-9%
70	2,533.6	173.1	2,706.7	(190.0)	(380.0)	2,136.7	2,000	(136.7)	-7%
80	3,082.6	553.1	3,635.7	(190.0)	(380.0)	3,065.7	[illegible]	[illegible]	[illegible]
Under Changes indicated in Sept 4th Handouts									
30	375.1		375.1		(190.0)	185.1	200	14.9	7%
40	985.1		985.1		(190.0)	795.1	800	4.9	1%
50	1,595.1		1,595.1		(190.0)	1,405.1	1,300	(105.1)	-8%
60	2,205.1	108.5	2,313.6		(190.0)	2,123.6	2,000	(123.6)	-6%
70	2,815.1	363.7	3,178.8		(190.0)	2,988.8	2,800	(88.8)	-3%
80	3,425.1	716.5	4,141.6		(190.0)	3,951.6	[illegible]	[illegible]	[illegible]
Incremental Change: Proposal less Current Law									
30	37.5		37.5	190.0	190.0	185.1	200	14.9	7%
40	98.5		98.5	190.0	190.0	478.5	600	121.5	20%
50	159.5		159.5	190.0	190.0	539.5	600	60.5	10%
60	220.5	108.5	329.0	190.0	190.0	709.0	700	(9.0)	-1%
70	281.5	190.6	472.1	190.0	190.0	852.1	800	47.9	5%
80	342.5	163.4	505.9	190.0	190.0	885.9	[illegible]	[illegible]	[illegible]

There are many other bells and whistles in the existing law, and their effect on individual taxpayers, or even on the totals, should not be trivialized. However, these numbers suggest, at least at this simple level of analysis, that the four items quantified in this report account for a great deal of the FY 2008 revenue change the Administration suggests will flow from their changes.

Attachment One: Simplistic Revenue Model

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General Calculation:
A: The 5 price scenarios shown in the September 4, 2007, handouts
B: Annual taxable volumes taken from the RSB, where the forecast is for 764,000 barrels a day. This is multiplied by 365 to convert to an annual number and .875 to remove royalty barrels (estimated at 12.5%) to yield 244 million taxable barrels a year.
C: The total value (of non royalty barrels) at destination is the product of price multiplied by taxable volume.
D: The estimate of 7.22 for downstream costs for FY 2008 is taken from the RSB, Table B-2b "Nominal Netback Costs- Forecast." This is multiplied times volumes for a total downstream cost of $1.762 billion.
E: Upstream costs are listed at page 16 of the RSB executive summary as $4,058.3 million.
F: The resulting production tax value is calculated at each price level by subtracting costs from destination value.

At this point, every calculation is done under existing law, then in accordance with the changes in the September 4, 2007, handouts, and, finally, the former is subtracted from the latter.

Base Rate:
G: Current law at 22.5% or proposal at 25%
H: Production tax value is multiplied by either 22.5% or 25%

Progressivity:
I: The Production Tax Value is divided through by taxable barrels to generate a per barrel value (Note: same calculation for existing law and proposed changes.)
J: Used to derive the Price Index Calculation. Either $40 or $30.
K: The Price Index is calculated where the per barrel value less the factor is positive.
L: The progressivity rate of .0025 or .002 per dollar of Price Index.
M: Price Index times progressivity rate.
N: This rate is then multiplied by the same Production Tax Value (as for the base rate.)
O. The total tax before credits is the sum of the base rate and the progressivity.
P. The TIE is calculated as 10% of the capital investments or as zero.
Q. Capital Investment credit calculated as 10 or 20% of capital investment (from DOR Petroleum Profits Tax (PPT) Implementation Report (August 3, 2007)
R. The two credits are then subtracted from the tax to arrive at the tax net of credits.
S. Tax extrapolated from the DOR handouts, rounded to the nearest 100 million dollars.
T. The difference between the DOR model and my simple build-up is the amount not accounted by the simple build-up.
U. This difference is also measured as a percent.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

Simple Model of FY 2008 Production Tax Revenue to match Administrations Sept 4th Handouts:

						Base Tax		Progressivity							Credits					
Price Scenarios on Sept 4 Handout	Annual Volumes (w/o royalty)	Total Destination Value of non Royalty Barrels	Less Downstream costs from RSB	Less Upstream costs (capex and opex) from RSB	Resulting Production Tax Value	Tax Rate	Base Tax Calculation at 22.5% and 25% and difference	Per Barrel Production Tax Value	Adjustment for Price Index Calculation	Price Index	Progressivity Rate per Price Index Dollar	Resulting progressivity rate	Progressivity Tax = Rate times value	Total Tax before credits	TIE Credits (Transitional Investment Expenditures)	Capital Costs * 20% or .10%	Tax net of credits	Tax per Price Scenarios on Sept 4 Handout	Unaccounted for in this simple model	Unaccounted for in this simple model (%)
$/bbl	MM bbls	MM $	MM $	MM $	MM $	%	MM $	$/bbl	$/bbl	$/bbl	%	%	MM $	MM $	MM $	MM $	MM $	MM $	MM $	%
A	B	C= (A * B)	D	E	F= (C+D+E)	G	H= (F*G)	I= (F/B)	J	K= (I-J)	L	M= (K*L)	N= (M*F)	O= (H+N)	P= (Q/2)	Q=	R= (O+P+Q)	S	T (S-R)	U= (T/S)
Under Current Law																Total Cost:				
	Per bbl:		(7.22)													1,900.0				
30	244	7,320	(1,762)	(4,058)	1,500	22.5%	337.6	6.15	40.00					337.6	(190.0)	(380.0)	-	-		
40	244	9,760	(1,762)	(4,058)	3,940	22.5%	886.6	16.15	40.00					886.6	(190.0)	(380.0)	316.6	200	(116.6)	-58%
50	244	12,200	(1,762)	(4,058)	6,380	22.5%	1,435.6	26.15	40.00					1,435.6	(190.0)	(380.0)	865.6	700	(165.6)	-24%
60	244	14,640	(1,762)	(4,058)	8,820	22.5%	1,984.6	36.15	40.00					1,984.6	(190.0)	(380.0)	1,414.6	1,300	(114.6)	-9%
70	244	17,080	(1,762)	(4,058)	11,260	22.5%	2,533.6	46.15	40.00	6.15	0.25%	1.54%	173.1	2,706.7	(190.0)	(380.0)	2,136.7	2,000	(136.7)	-7%
80	244	19,520	(1,762)	(4,058)	13,701	22.5%	3,082.6	56.15	40.00	16.15	0.25%	4.04%	553.1	3,635.7	(190.0)	(380.0)	3,065.7	[illegible]	[illegible]	[illegible]
Under Changes indicated in Sept 4th Handouts																				
30						25.0%	375.1	6.15	30.00					375.1		(190.0)	185.1	200	14.9	7%
40						25.0%	985.1	16.15	30.00					985.1		(190.0)	795.1	800	4.9	1%
50						25.0%	1,595.1	26.15	30.00					1,595.1		(190.0)	1,405.1	1,300	(105.1)	-8%
60						25.0%	2,205.1	36.15	30.00	6.15	0.20%	1.23%	108.5	2,313.6		(190.0)	2,123.6	2,000	(123.6)	-6%
70						25.0%	2,815.1	46.15	30.00	16.15	0.20%	3.23%	363.7	3,178.8		(190.0)	2,988.8	2,800	(188.8)	-7%
80						25.0%	3,425.1	56.15	30.00	26.15	0.20%	5.23%	716.5	4,141.6		(190.0)	3,951.6	[illegible]	[illegible]	[illegible]
Incremental Change: Proposal less Current Law																				
30							37.5							37.5	190.0	190.0	185.1	200	14.9	7%
40							98.5							98.5	190.0	190.0	478.5	600	121.5	20%
50							159.5							159.5	190.0	190.0	539.5	600	60.5	10%
60							220.5		(10.00)	6.15		1.23%	108.5	329.0	190.0	190.0	709.0	700	(9.0)	-1%
70							281.5		(10.00)	10.00		1.69%	190.6	472.1	190.0	190.0	852.1	800	(52.1)	-7%
80							342.5		(10.00)	10.00		1.19%	163.4	505.9	190.0	190.0	885.9	[illegible]	[illegible]	[illegible]

SB 2001/HB 2001
October 20, 2007
Supplement to the Sectional Analysis of October 1 2007
Authors: Dan Dickinson & Steve Porter

Approximately 50 sections of the bills submitted on the first day of the special session were changed from the October 1 work draft. Where those changes were only punctuation, style, word, or grammar edits that do not affect the original analysis they are merely listed as "minor changes."

Minor changes – Section 1

Section 2 – Expands "data" that must be provided by DNR to DOR to "reports, files and other information."

Section 8 – Although this section adds approximately 5 pages of text to the bill, it merely restates the entire existing text of AS 38.05.180 (j) in order the make a change to AS 38.05.180(j) (6) (B). Section 8 was originally just the text of AS 38.05.180(j) (6) (B).

Section 10 – Adds Department of Natural Resource royalty auditors to the list of exempt employees.

Minor changes – Sections 15 – 22; 24 – 26

Section 26 also incorporates two substantive changes.

1. If more than one explorer holds an interest in a well, to obtain a .023 credit for exploration, that explorer, and any others holding an interest in the exploration, have to agree in writing not to invoke their rights to have information held confidential by DNR longer than 2 years.

2. The two legacy fields – Prudhoe and Kuparuk are "combined." Credits still cannot be applied against taxes from other non-legacy fields. However, unlike the October 1 work draft of the bill, credits from one legacy field can be applied against taxes from the other.

Minor changes – Sections 27 – 29; 36 – 39

Section 39 also incorporates two substantive changes

1. If more than one explorer holds an interest in a well, to obtain a .025 credit for exploration, that explorer, and any others holding an interest in the exploration, have to agree in writing not to invoke their rights to have information held confidential by DNR longer than 2 years.

2. The 30 day period that an explorer has to provide certain data to DNR may be extended to "a period provided by the Department of Natural Resources."

Minor changes – Sections 42, 44 – 46

Section 47 - Makes clear that the $1,000 a day reporting penalty applies to both "reports" and "statements."

Minor changes – Sections 48 – 50

Section 51 – Authorizes the DOR to issue non-binding "advisory" opinions. The opinion is not binding on the DOR, meaning that if a taxpayer relies on the opinion and the department subsequently changes its mind, merely having followed the advisory opinion does not shield the taxpayer from interest and penalties.

Minor changes – Sections 42, 54, 55, 56

Section 58 – Adds any costs arising from "violations of law, or failure to comply with an obligation under a lease, permit or license issued by the federal government" to the list of costs which must be excluded from qualified lease expenditures.

Minor changes – Sections 59, 60 and 62

Section 63 (a), (b) and (c) are now section 63, 64 and 65, and subsequent sections 64 – 71 are renumbered 66 – 73.

In the new Section 67, DNR auditors are given (as DOR auditors were in the original bill) 90 days to opt to either become exempt or to retain their status in a union position.

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal

Statute Section is AS 43.55.xxx unless other wise indicated

Base Rate

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Base Rate	15, 17	.011(e) & (g)	22.5%	25%

Tax on Private royalties under .011 (i) not changed (section 23 corrects reference)

Progressivity

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Difference subtracted from net (Production Tax) Value to Arrive at Price Index - (i.e. progressivity starting point)	17, 18	sec .011(g) & (h)	$40	$30
Progressivity Tax per dollar of Price Index	17, 18	.011(g) & (h)	0.25%	0.20%
Progressivity Calculation Averaged over what Period?	17, 18	.011(g) & (h),.160 (a)	Month	Year

Floor

sections 15,16, and sections 32-36, 41-42 to remove ability to apply credits

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Base	16	.011(f)	Entire North Slope collectively, before application of credits	Prudhoe & Kuparuk, Individually (no other fields come close to 1 billion barrel standard), after application of credits
Gross Calculation	16	.011(f)	No change: Gross Value at Point of Production	
Rate	16	.011(f)	ranges from 0% to 4%	10%
Can credits be applied to further reduce tax if floor applies?	16	.011(f)	Exploration (.025) and Non Transferable (.024) credits can be applied against floor, Investment and all other .023 credits cannot	No
Status of credits not used because of floor	16	.011(f)	implicit: can be carried forward, or applied to non North Slope areas	explicit: only applied against that legacy field: when carried forward

Credits

Investment & Loss Forward Credits (.023 Credits)

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Investment Credits	26	.023(a)	Taken in year of investment	Maximum of 50% of any year's credits taken in that year.
Applied against tax due under floor?	26	.023(a)	No change: .023 credits cannot be applied against tax due calculated under the floor	

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal

Statute Section is AS 43.55.xxx unless other wise indicated

Investment & Loss Forward Credits (.023 Credits) cont.

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Loss Carry Forward Credits	27	.023(b)	20%	25%
Restrictions on use of Loss Carry Forward Credits	27	.023(b)	no similar restriction	explicit: if costs occurred in legacy field subject to floor, loss can only be applied against that field.
Restrictions on use of Purchased Credits	28,29	.023(d)	Can be taken any time although cannot be applied against more than 20% of tax due	50% of credit cannot be taken until following year. (retains 20% rule)
Transitional Investment Credits	63	.023(i)	Qualified investment from 2001 - 2006 used as a credit at 10% if matched by new investment.	eliminated

Nontransferable Credits (.024 Credits)

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Applied against tax due under floor?	41,42, 32-36	.024 (a),(c),(e), (g)	Yes	No

Exploration Credits (.025 Credits)

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Applied against tax due under floor?	36, 41	.025(a) & (h)	Yes	No
Disallowances	37	.025(b)	"administration, supervision...management... community relations or environmental costs..." not allowed	adds "costs arising from gross negligence or violations of health, safety, or environmental statutes or regulations" to costs not allowed
DNR approval and 3 mile rule for 40% credit	38	.025(c)	Bottom whole must be more than 3 miles from previously drilled bottom hole, except in CI, if DNR determines "distinct exploration target"	Before drilling DNR must make determination that new target "distinctly separate from any trap that has been tested by preexisting well," <u>and</u> after drilling DNR must determine well achieved objective <u>and</u> if not in CI bottom hole must b~ 3 miles from previously drilled bottom hole.

note: .025(d) and (e) unchanged

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal

Statute Section is AS 43.55.xxx unless other wise indicated

Exploration Credits (.025 Credits) Cont.

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Data Explorer must submit to DNR	39	.025(f)(2)(A)&(B)	explorer must provide DNR with list of "data sets available"	Detailed list of data
Confidentiality of Well Data	39	.025(f)(2)(c)	10 years	24 months
note: Seismic data still at 10 years				
Applicability of Credit Certificates	39	.025(f)(5)	Can be used immediately	2 certificates, each for 1/2 of amount, one certificate cannot be used until the following calendar year
Non Confidential Information	39	.025(f)(5)	under general tax confidentiality rules	Explorer, location and date of work and when it will become public is public
Tax Exempt Entities Ability to Sell Credits	31,40	.025(g)	not mentioned	not allowed
Applied Against Tax Due under Floor?	36, 41,42	.025(a), (h) and (i)	Yes	No
Definition of Pre-Existing Well - in Effect Whether Delineation Wells Qualify for Credits	43	old .025 (c)(2)(a) new .025(k)4	preexisting well is one that was spudded more than 150 days and less then 35 years earlier. Limits ability to come back next season and get credit for delineation well.	preexisting well is one that was spudded more than 540 days and less then 35 years earlier. Allows two seasons worth of work to qualify for credit.
note: .025(i) appears to have also been rewritten for clarity in section 42 and definitions are moved to (k) in section 43 or added in 62				
"DNR TIE" Seismic Credits	44	.025(l)	none	If DNR deems "best interests of state" served by acquisition and distribution of seismic data shot before 2003, a 5% credit allowed for cost.

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal

Statute Section is AS 43.55.xxx unless other wise indicated

Allowable Lease Expenditures

.160 great simplified in sections 52, 53 and 63 as monthly reporting calculations no longer needed.

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Carry Forward of Unused Lease Expenditures	54	.160 (e)	Lease expenditures that would reduce production tax values below zero can be used to establish a loss carry forward credit under .023(b)	Adds two more categories that can be used for carry forward credit: costs not associated with production or ownership interests

.165 Reorganized for clarity and as to between what is in (a) and what is in (b) in sections 56 & 57

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Cost must allowed in department's regulations?	56	165(a)	no	yes
Use Portions of Existing Cost Sharing Agreements or intra-producer audits to determine costs?	63	.165(c) & (d)	allowed	not allowed
DR&R Allowed?	58	.165(e) (15)	allowed for portion allocated to production after April 1, 2006	not allowed at all
Deferred Maintenance allowed?	58 & 64	new .165(e) (19)	Allowed	not allowed if undertaken in response to an problem which required a reduction in production, unless caused by something unavailable even to someone exercising due care.
Field Topping Plants allowed?	58	new .165(e) (20)	Allowed	not allowed; however a deduction for the 'fair market value' of the products from the topping plant will be allowed.

State Purchase of Credits

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Funding of Purchase of .023 and .025 Credits by State	30,45	new.028 replaces .023(f)	"subject to appropriations made by law"	Creates the oil and gas credit fund, which is funded by 10% or 15% of production taxes depending on whether ANS WC is forecast (when?) to above $60 or below $60. Credits are purchased from fund.
Limits on Purchase of .023 and .025 Credits by State	30,45	new.028 replaces .023(f)	Entity receiving refund had to (i) have been producing fewer than 50,000 bbls a day (currently all but big three); (ii) reinvest that money in state, (iii) had no other delinquent taxes and (iv) was limited to $25 million a year	Same restrictions except $25 million cap eliminated

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Statute Section is AS 43.55.xxx unless other wise indicated

Information

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Required Reporting of Forward Looking Information	49	.040 (5)	none	requires taxpayer "to file report and copies of records that are considered by the department as necessary to forecast state revenues under AS 43.55". For unit with multiple working owners limited to unit budget matters. Penalty of not more than $1000 a day. Not clear how far in advance data must be disclosed to avoid penalty.
Disclosure of Tax Information	61	old 43.05.230 new .890	Published information must combine data. so as to "prevent the identification of particular returns."	As long as data is aggregated among 3 producers 11 categories of data can be made public (production, taxes, effective tax rates, gross value, costs, production tax value and credits). Such aggregation is explicitly "irrespective of whether the information...prevents[s] the identification of particular reports." (i.e. one large taxpayer aggregated with two very small taxpayers)
DNR Sharing Royalty Information with DOR	2-9 & 11	royalty statutes	limited ability	expanded ability
DOR Sharing Tax Information with DNR	12-13	AS 43.05.230	limited ability	expanded ability
Required Reporting	46	.030(a)	"The person paying the tax..." will report "with other information required" certain data	Producer (whether tax due or not) will report same information plus certain cost, credit and monthly data. Penalty of not more than $1000 a day.
Required Reporting	48	.030(e) & (f)	some requirements in regulations	in statute: thorough reporting of costs, volumes, sales, monthly estimates and other information required by department

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal

Statute Section is AS 43.55.xxx unless other wise indicated

Statute of Limitations

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Statute of Limitations	1, 14, 50	old 43.05.260 new .075	3 Years for all Taxes	6 years for Production Ta::

DOR Auditors

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Are DOR auditors exempt employees?	10,65,67	new AS 39.25.110	no	yes

Other Administrative Provisions

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
Monthly filings	22, 24,25	0.02	ambiguity (tried to resolve in regulations) about interaction between annual tests and credits and monthly filings	Clear and separate rules for (i) non CI, not subject to floor under (f), (ii) CI, and (iii) subject to floor under (f).
Penalty for Failure to Report (when no tax is due)	47	.030(d)	none (penalty was tied to tax being due)	up to $1,000 a day under departments regs
Retroactive Changes Require Payment	50	new .075	Regulatory provision 15 AAC 55.200	Incorporated into Statute
Electronic Payment and Filing	51	.110(e)& (f)	silent	DOR may require

sections 66 & 67 are transitional rules

Cook Inlet - no substantive change, however regs imported into statute

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
CI Allocation Rules	19 - 21, 55, 59	new .165(f)-(i)	Allocations and trying to fit all the other terms of the statute into the statutory ceiling language found in 15 AAC 55.360, 15 AAC 55.223 & 15 AAC 55.235.	adopted into statute

Effective Date

Issue	Bill Section	Statute Section	Current Law	Governor's 10/1/2007 Proposal
General Rules	64, 69			Jan 1 2008
Deferred Maintenance Rules	64	new .165(e)(19)		Apr 1 2006

Governor's Proposed Production Tax Legislation

October 1 2007

Sectional Analysis

Authors: Dan Dickinson & Steve Porter

Section 1 Uncodified Laws (Legislative Intent)

Legislative Intent – refers to changes made in Section 50, page 31. It suggests that the changes are only clarifying a long-standing interpretation of AS 43.05.260 by the Department of Revenue (DOR). Details will be discussed in Section 50.

Section 2 AS 38.05.035(a)

This section allows the DOR access to the Department of Natural Resources (DNR) confidential information for

1) its use in forecasting state revenue under AS 43.55 or

2) administering AS 43.55, the production tax

In an apparent stylistic change this draft deletes previously repealed portions of AS 38.05.035(a) requiring subsections references to change as indicated in bill sections 3-9 below.

Section 3 AS 38.05.036(b)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 4 AS 38.05.036(f)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 5 AS 38.05.036(g)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 6 AS 38.05.123(f)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 7 AS 38.05.133(e)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 8 AS 38.05.180(j)(6)(B)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 9 AS 38.05.275(c)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 10 AS 39.25.110(42)

Section 39.25.110 is exempt service. This section adds oil and gas auditors performing production tax auditors and their immediate supervisors to the exempt service. This leaves oil and gas income tax auditors in the classified service.

Section 11 AS 41.09.010(d)

Conforming references in Title 41 required by renumbering in sec. 2 of the proposed legislation.

Section 12 AS 43.05.230(a)

Section 43.05.230 covers disclosure of tax returns and reports. Section 43.05.230(a) (5) adds a reference to AS 43.55.890. The reference to AS 43.55.890 (new section discussed in Section 61) in the proposed legislation would create an exclusion for certain information if aggregated

among three or more producers or explorers. This type of information would be allowed under AS 43.05.230(e) if the publication of the statistics was so classified as to prevent the identification of a particular tax payer's return or report. The new section would seem to lower the standard. This proposal would permit information which was "aggregated among three or more producers or explorers" to be divulged to the public even if, for example, a very large taxpayer's information was aggregated with two very small taxpayers so that the large taxpayer's individual taxpayer information could easily be extracted from the information disclosed.

Section 13 AS 43.05.023(h)

The Department of Revenue currently has the authority to share copies of returns, reports, and documents filed under AS 43.65 (Mining License Tax) with DNR. This language broadens the authority of DOR to also share returns, reports and documents filed under AS 43.55 (Oil and Gas Production Tax and Oil Surcharge) with DNR.

Section 14 AS 43.05.260(a)

This section adds AS 43.55.075 (Section 50 of this legislation) to the exceptions to the requirement to have taxes imposed within three years after a return is filed. Details will be discussed in Section 50.

Section 15 AS 43.55.011(e)

The current production tax is calculated on a monthly basis. In the proposal tax would be calculated based on a calendar year. This structure of the law is also changed. Currently AS 43.55.011(e) establishes the base tax rate (22.5%), and progressivity was dealt with elsewhere. However now this section refers to the percentage determined in AS 43.55.011(g) where both the base and progressivity rates would be established. This simplifies the comparison with the floor in AS 43.55.011 (f) - which is compared with a combined base and progressivity tax.

Section 16 AS 43.55.011(f)

This section makes changes to the minimum tax.

The current minimum tax is applied is 4% of gross value at the point of production over $25, 3% of gross over $20, 2% of gross over $17.50 and 1% of gross over $15 and 0% for $15 and under. The new minimum tax is 10% of gross value at the point of production.

The current minimum tax is applied to all oil and gas produced north of 68 degrees North latitude, i.e. the entire North Slope. The proposed minimum tax would apply only to oil and gas produced from leases or properties within a unit or non-unitized reservoir that have cumulatively produced one billion BTU equivalent barrels of oil or gas and from which the average daily oil and gas production during the most recent calendar year exceed 100,000 BTU equivalent barrels. Based on this limitation, the new minimum tax would only apply to oil and gas produced at Prudhoe Bay and Kuparuk.

The current floor compares net values to gross values, and then allows certain credits to be applied against the result – even against the floor. The proposed floor test compares 25% of net plus any progressivity less any credits with 10% of gross. If 10% of gross is higher, that is the tax and a taxpayer may not apply tax credits to reduce its tax liability to below 10 percent of total gross value at the point of production.

Section 17 AS 43.55.011(g)

This section proposes a tax of 25 percent plus 0.2 percent times the progressivity price index, defined in .011(h), however the sum is not to exceed 50 percent. The current law is 22.5 percent

plus 0.25 percent times the progressivity price index, however the sum is not to exceed 47.5 percent.

Section 18 AS 43.55.011(h)

This section amends the price index from a monthly calculation to a calendar year calculation.

This section also changes the starting net value of progressivity from $40 to $30 a barrel.

Section 19 AS 43.55.011(j)

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

Section 20 AS 43.55.011(k)

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

Section 21 AS 43.55.011(m)

This section clarifies what a producer could claim in excess credits from Cook Inlet against taxes on leases or properties elsewhere in the state.

If the amount of excess adjusted lease expenditures multiplied by 25 percent is greater than or equal to the total of the reductions for all leases calculated under the Cook Inlet ceilings in AS 43.55.011(j) or (k) , the total calculated under this paragraph would be zero.

Otherwise the remainder calculated by subtracting the excess adjusted lease expenditures multiplied by 25 percent from the total of the reductions for all leases calculated under AS 43.55.011(j) or (k) would be the total calculated under this paragraph.

This language is currently found in regulation at 15 AAC 55.360 (d)

Section 22 AS 43.55.020(a)

This section would reconcile the monthly installment payments of tax to be consistent with other proposed changes, and incorporates some regulatory solutions to some of the ambiguities in the existing legislation concerning Cook Inlet ceilings and credits that could only be applied on an annual basis.

Section 23 AS 43.55.020(d)

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

Section 24 AS 43.55.020(g)

Reference changes and clarifies annual due date.

Section 25 AS 43.55.020(h)

Reference changes and clarifies annual due date.

Section 26 AS 43.55.023(a)

This section stipulates that no more than half of a capital expenditure tax credit may be applied in a single year.

Section AS 43.55.011(f) states that a tax credit may not be applied to reduce a producer's tax liability below 10 percent of the total gross value at the point of production. This section deals with the excess tax credit left over after a producer reduces their tax to 10% of gross. This section stipulates that the excess tax credit left over may not be used to reduce the producer's taxes outside that unit.

A significant portion of the language -which had originally been copied from section .025 –would now be invoked by referencing AS 43.55.025(f).

Section 27 AS 43.55.023(b)

This section changes the amount of carried-forward annual loss that may be taken as a tax credit from 20 percent to 25 percent. (In current law the loss carry-forward at 20% does not equal the base tax rate at 22.5% percent.)

This section also prevents lease expenditures subject to AS 43.55.011(f) i.e., Prudhoe and Kuparuk, from contributing to a carried-forward annual loss.

Section 28 AS 43.55.023(d)

This section would end the ability to transfer or obtain a cash payment for an unused tax credit under AS 43.55.028 (new section) if that unused tax credit is described in the floor sections (i.e. Prudhoe Bay or Kuparuk.)

This section changes the time period that the department has to grant or deny the application from 60 days to120 days and amends the language that designates the start of the 120 day period.

This section also splits the certificate into two transferrable tax credit certificates, one that is available to use any time and the other that is not available until the next calendar year.

Section 29 AS 43.55.023(e)

Conforming changes to changes made in the proposed legislation.

Section 30 AS 43.55.023(g)

Conforming changes to changes made in the proposed legislation.

Section 31 AS 43.55.023(l)

This new section clarifies that an entity which is exempt from tax under the chapter cannot apply for a transferable tax certificate (for example the Alaska Natural Gas Development Authority or the Alaska Gasline Port Authority.) See section 40

Section 32 AS 43.55.024(a)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 33 AS 43.55.024(c)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 34 AS 43.55.024(e)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 35 AS 43.55.024(g)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 36 AS 43.55.025(a)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 37 AS 43.55.025(b)

This section changes the date for expenditures for work performed to be eligible for a production tax exploration credit from July1, 2003 to December 31, 2007. (That is, even if this bill becomes law, the old rules will apply through December 31, 2007.)

This section adds the obligation that a well must be "completed or abandoned" at the time the explorer claims the exploration credit. Application would not be allowed prior to finishing the well.

This section would exempt costs arising from gross negligence or violations of Health Safety & Environmental statutes or regulations from expenditures that qualify for the exploration credit.

Section 38 AS 43.55.025(c)

The current law requires a well to be drilled 3 miles away from a preexisting well to be eligible for a credit, except in CI, where DNR can certify that the well tests a "distinct exploration target". The proposed law would require

(1) That the well be drilled to a structural or stratigraphic trap that is distinctly separate from any trap that has been tested by a preexisting well, with this determination made by the commissioner of DNR before the well is spudded;

(2) The existing three mile requirement for all wells not in the CI, and

(3) The commissioner of DNR to determine, after the well is completed or abandoned that the well adequately achieved the explorer's stated objective.

Section 39 AS 43.55.025(f)

This section defines what data would be necessary to be submitted to claim an exploration credit. The new language clarifies the obligation of the explorer to provide the DNR with all seismic data, on state lands and off state lands, within and outside unit boundaries.

In the case of well data the proposed legislation reduces the time period the data is required to be kept confidential from 10 years to 2 years. In addition AS 31.05.035(c) allowed an explorer to request the DNR to extend the time of confidentiality from 2 years for as long as necessary. The proposed legislation in (D) prohibits the explorer from requesting an extension if they want the credit.

This section also explains that the certificate issued will be two certificates, each for half the credit, one to be used whenever the explorer wants and one not to be used before the next calendar year. All certificates will have the date on which the information required to be submitted will be released.

Section 40 AS 43.55.025(g)

This new section clarifies that an entity which is exempt from tax under the chapter cannot transfer a transferable tax certificate (for example the Alaska Natural Gas Development Authority or the Alaska Gasline Port Authority.) See section 31

Section 41 AS 43.55.025(h)

Proposal changes law so .025 credits cannot be applied against the tax floor in .011 (f).

Section 42 AS 43.55.025(i)

Proposal changes law so .025 credits cannot be applied against the tax floor in .011 (f), and recognizes the proposed change from a monthly to an annual tax.

Section 43 AS 43.55.025(k)

This section changes the definition of preexisting well from a well spudded more than the150 days to 540 days in the proposed legislation. In other words, it expands the window to qualify as an exploration well from one season of work to two seasons, and thus may include delineation wells.

Section 44 AS 43.55.025(l)

This new section would allow the DNR approve a credit for seismic shot prior to July 1, 2003 if the Commissioner of DNR finds it in the best interest of the state to acquire the seismic for public distribution. The credit would be 5% of the old investment expenditure.

Section 45 AS 43.55.028

This section would create an oil and gas tax credit fund to purchase certain transferrable credit certificates issued under AS 43.55.023. The amount of revenue deposited into the fund would be based on the average price value forecast by the DOR of ANS oil sold on the West Coast. For $60 or higher the percentage is 10%; for less than $60 the percentage is 15%. For example,

the current forecast by the DOR for 2008 is $51.25; so 15% of all revenues production tax received during 2008 would go to the fund after deposits to the CBR. Production tax revenues for 2008 are forecast to be $995.4 million; so, the deposit to the fund would be approximately $150 million. If the DOR projections are wrong or the tax is increased, the amount going into the fund would be different.

The department would be able to use the fund to purchase tax certificate but the purchase could not exceed the amount incurred by the applicant for qualified capital expenditures or lease bonuses in the 24 months subsequent to the application. The applicant's total production cannot exceed 50,000 BTU equivalent barrels per day, thus excluding the 3 largest taxpayers. All the qualifications currently found in AS 43.55.023 (f) (which is repealed under this proposal) have been retained, except the maximum of $25 million a year to each taxpayer

Section 46 AS 43.55.030(a)

This section would amend what a tax payer is required to file by March 31st of the following year. It makes explicit the requirement to submit the costs for transportation of the oil and gas, qualified capital expenditures, and lease expenditures under AS 43.55.165 and 170, the production tax value of the oil and gas, and any claims for credits.

Section 47 AS 43.55.030(d)

This section defines the penalties of up to $1,000 a day for not filing the required reports.

Section 48 AS 43.55.030(e-f)

Section (e) would add a reporting obligation to explorers that do not produce oil or gas.

Section (f) details what the department could require of a producer, explorer, or operator on a monthly basis.

Section 49 AS 43.55.040

This section would add a clause to the powers of DOR giving them the right to require a producer, explorer or operator to file reports that are "considered necessary" to forecast state revenue under AS 43.55. To the degree that this lines up with statutory authority (37.07.060 (b) (4), the forecast is for the current and next fiscal year; however the limitation is not explicit.

The section also provides for penalties of up to $1,000 a day for a person that does not file the reports "considered necessary" by the department.

Section 50 AS 43.55.075

This section was referred to in the legislative intent language of the proposed legislation – which recognizes that historically most production tax audits took longer than 3 years and relied on AS 43.05.260(c) (3) which permits a longer audit if the "taxpayer … consented in writing". The proposal requires the amount of tax imposed by this chapter to be assessed within 6 years after the latest return is filed. The section also details various filing time period obligations.

Section 51 AS 43.55.110(e-f)

Section (e) allows the department to require electronic filing

Section (f) allows the department to require electronic payments

Section 52 AS 43.55.160(a)

This section is a simplified rewrite of existing law, a consequence of no long having to do monthly calculations for progressivity.

Section 53 AS 43.55.160(b)

Continues the simplification from the prior section

Section 54 AS 43.55.160(e)

The proposal would expand section (e) to include among the costs that may be used to generate loss carry forwards those costs associated with leases of a producer that are not producing oil and gas or are on lands where the producer does not own an operating or working interest.

Section 55 AS 43.55.160(f-I)

This section deals with allocations of costs that a taxpayer incurs in one lease or property against revenues from another lease or property. Proposed North Slope rules are in (f), New Area Development rules are in (g) and Cook Inlet rules are in (h) and (i). This section would import regulatory language into the statute:

Section (f) clarifies that costs subject to the floor in AS 43.55.011(f) could not be allocated to other leases or properties. Otherwise costs must be allocated to producing properties

Section (g) applies to leases outside the North Slope and outside Cook Inlet, in other words costs that qualify for the .024 new area development credit. Those expenditures must be applied to leases outside the North Slope and outside Cook Inlet.

Section (h) deals with CI allocations and which costs (defined as "Cook Inlet excess adjusted lease expenditures") can be used in calculating carried-forward annual loss These rules are currently found in regulations in15 AAC 55.235.

Section (i) sets forth the calculations for determining the carried-forward annual loss in (h), using rules currently found in regulations in 15 AAC 55.223.

Section 56 AS 43.55.165(a)

Section (a) is rewritten and would delete the "typical industry practices and standards" language in the current legislation. The language that is deleted from (a) is inserted in (b).

Section 57 AS 43.55.165(b)

Section (b) was modified by deleting reasonable allowance language that was inserted in 165(a).

Section 58 AS 43.55.165(e)

The current law allows for the costs for dismantlement, removal, and surrender or abandonment (DR&R) to qualify as lease expenditures if they are incurred after April 1, 2006. The proposed legislation would disallow all dismantlement, removal and surrender or abandonment costs to qualify as lease expenditures.

Section (19) was added to (e). It would disallow costs incurred for repair, replacement, or deferred maintenance that is undertaken in response to a failure or problem that results in an unscheduled interruption or reduction in the rate of oil or gas production.

Section (20) was added to (e). It would disallow costs of refineries or crude oil topping, plants, including those on the North Slope that produce fuel for North Slope production operations. Instead a taxpayer will be allowed a deduction for what it (and the State's auditors) reckons is the "fair market value" for refinery products less the underlying value of the oil used in the refinery.

Section 59 AS 43.55.165(h)

The original language of this section directed the department to write regulations where (as in CI under .011(j) and .011(k)) lease costs need to be allocated between oil production and gas production. The proposed change would expand that directive to include any required allocation of costs.

Section 60 AS 43.55.170(a)

This section would delete qualifying language regarding payment or credit that has already been subtracted in calculating billable or billed costs under AS 43.55.165(c) or (d).

Section 61 AS 43.55.890

This is a new section regarding the disclosure of tax information. It would allow the department to publish certain information if the information is aggregated from three or more producers or explorers. The potential impact of this change was previously discussed in Section 12.

Section 62 AS 43.55.900

This section adds the definitions of "non-unitized reservoir", "pool", "producer", and "unit"

Section 63 Repeals

This section would repeal the following:

AS 43.55.023(f), (State purchase of certain credits),

AS 43.55.165(c), (Use of operating agreements)

AS 43.55.165(d), (Use of audits under operating agreements)

AS 43.55.011(l), (Ordering of CI taxes against credits)

AS 43.55.023(i), (Transitional Investment expenditure credits),

and AS 43.55.160(c), (Monthly allocation of annual costs).

Section 64 Uncodified Laws

This section stipulates the applicability dates for each of the sections. In general, the new rules would become effective January 1, 2008, except for the deferred maintenance/corrosion provisions of .165 (e) (19) which would be retroactive to April 1, 2006.

Section 65 Auditors

This section would assign oil and gas auditors to exempt service.

Section 66 Retroactivity of Regulations

This section stipulates the dates on which the regulations implementing this statute could apply.

Section 67 Pending Applications

This section stipulates how to handle credit applications that are currently pending before the Department and have not been approved.

Section 68 Regulations

This section would grant DOR and DNR the authority to adopt regulations necessary to implement this legislation.

Section 69 Retroactivity

This provision explicitly provides that certain provisions of the act are retroactive to specific dates.

Summary Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law

Issue	Current Law	Governor's 10/1/2007 Proposal
Base Rate	*AS 43.55.011 (e) & (g)*	*Bill Sections 15 & 17*
Base Tax Rate	22.50%	25%
Progressivity	*AS 43.55.011(g) & (h)*	*Bill Sections 17,18*
Starting point	$40	$30
Tax/$ of Price Index	0 25%	0.20%
Average Value over	month	year
Gross Value Floor	*AS 43.55.011(f)*	*Bill Section 15, 16, 31-36, & 41-42*
Base	Prudhoe & Kuparuk	North Slope
Rate	ranges from 0% to 4%	10%
Credits further reduce floor tax?	Yes	No
Credits	*AS 43.55.023 and 55.025*	*Bill Section 26-28, 38-44 & 63*
Investment Credits	Taken in year of investment	1/2 in each of two years
Loss Carry Forward Credits	20%	25%
Transitional Investment Credits	Yes	No
Exploration Credits	*AS 43.55.025*	*Bill Section 36 - 44*
DNR approval required?	In CI, to avoid 3 mile limit	Always
Confidentiality of well data	10 years	2 years
Pre-existing well	One drilling season	Two consecutive drilling seasons
"DNR TIE" Credits for pre 2003 seismic work?	no	5%
Allowable Lease Expenditures	*AS 43.55.165*	*Bill Sections 52-64*
Use producer audits of operators?	Yes	No
DR&R Allowed?	Some	No
Deferred Maintenance allowed?	Yes	No
Field Topping Plants allowed?	Yes	No

Summary Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law

Issue	Current Law	Governor's 10/1/2007 Proposal
State Purchase of Credits	*AS 43.55.023(f) & (g)*	*Bill Section 45 (AS 43.55.028)*
Paid from:	"appropriations made by law"	oil and gas credit fund, funded from production taxes
Annual dollar cap per taxpayer?	$25 million	none
Information	*AS 43.05.230 and royalty statutes*	*Bill Sections 2-9,11-13, 49 & 61*
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day.
Disclosure of tax information	if aggregated to "prevent the identification of particular returns."	if aggregated w/2 other producers
DNR sharing royalty information w/ DOR	limited ability	expanded ability
DOR sharing tax information with DNR	limited ability	expanded ability
Statute of Limitations	*AS 43.05.260*	*Bill Sections 1,14,50 new AS 43.55.075*
State assessment must be issued within	3 yrs	6 yrs
DOR Auditors	*As 39.25.100*	*Bill Sections 10, 65, 67*
DOR auditors exempt employees?	no	yes
Effective Date		*Bill Section 64*
Generally		Jan 1 2008
Deferred Maintenance Rules		Apr 1 2006

Senate Resources

Comments on Governor's ACES Proposal

Steven B Porter

10/22/2007

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Stability

1) Decision on Prudhoe Bay Satellites - Borealis, Midnight Sun, Orion, Polaris, Point McIntyre, and Aurora are integrated and collectively managed. Merely implemented the intent of the statute. When you consolidate wells with PBU facilities the regulations contemplate consolidation for tax purposes.
2) PPT tax. The producers have generally opposed any changes to the ELF prior to the SGDA negotiations. They liked the economics of ELF but knew they were going to have to agree to some change in order to get
   a. Fiscal certainty under their contract
   b. They were also hoping for contract approval if they agreed to the change
   c. They lost on all counts.
      i. They did not get the tax they "agreed to"
      ii. They did not get any type of certainty on the tax
      iii. They did not get the contract
3) The governor has called you back to review the tax because of the "cloud" on the tax. I don't think this review will cause the world to see you as unstable. The industry will certainly say it is true, but anyone who really looks underneath their rhetoric will know the truth. They also know the truth. This is merely an evaluation of what was done – with a possible early mid-course correction.
4) If you change the tax now and change it again during the regular session, there may be a problem.

Alaska's Prospectivity

1) Oil
    a. State lands- less than 20% of the future potential are on state lands where we receive both royalty and tax.
        i. Puddles
        ii. Heavy Oil – will come back to this
    b. NPRA – around 30% of future potential is in NPRA
        i. No royalty but ½ the royalty comes back to the state first as impact aid, then to fund PCE then another fund before it has a possibility to get to the general fund. Of the millions of dollars that the state has received from NPRA I don't think any of it has reached the general fund.
        ii. Taxes – you still get taxes. But high costs will result in high opex and capex.
    c. Offshore OCS – over 50% of future potential is in the OCS
        i. No royalty
        ii. No taxes
    d. What is the future vision for oil
        i. Gov should go to congress and get us the same as the Gulf States have. They get a share of the OCS revenues because the feds recognize that the local state jurisdictions are impacted by OCS development – and they can oppose it and prevent it from proceeding forward
            1. This should be before shell drills any exploration wells

2. Should work with the NSB to make sure that the operations in the OCS minimize the impact to the environment and local communities and subsistence culture

ii. Heavy oil should be encouraged because it has the greatest chance on state lands of contributing to the future revenue stream of the state

1. One of the slides yesterday showed the industry doing stress case economics at $40. Commissioner Galvin stated that heavy oil will be impacted around $41 dollars from the implementation of the 10% gross tax which means that we may actually create a situation where we have prevented or slowed one of the most prospective oil reservoirs on state lands by passing the gross minimum tax. The minimum tax looks like it was designed to penalize heavy oil not help it.

e. Alaska competitiveness –

i. We are a mature (between Colville and canning) province as far as oil is concerned. Geology is king. Heavy oil and puddles

ii. NPRA has larger potential in the Alpine type range

iii. OCS still has the elephants but at great cost and high environmental/legal risk.

2) Gas

a. Pedro said the gas pipeline was uneconomic

b. I would call it indeterminate

i. Four things needed to say economic or uneconomic

1. Costs of the pipeline
2. Future price of gas
3. Stability of the taxes and what they are
4. Internal Rate of Return/Project evaluation criteria

c. The submittal of the proposals will not change the above substantially unless the applicants accepts, transfers, or provides a way to handle some of the above risks to the state's and the shipper's satisfaction.

d. When the proposals come out at the end of November the state should review the proposals then evaluate how they can help the state move the project forward. The project is not a gasline through Canada or an LNG line to Valdez. It is monetizing the North Slope gas resource to the greatest benefit of the people of the State of Alaska. It may mean making adjustments to the law in January. It may mean taking a new course, it also may mean AGIA is working and all that needs to be done is to implement it.

3) Timing of development in general and gas pipeline development specifically.

a. A reasonable timeline for gas pipeline development is at least 10 years. Anything less than that you need to examine the proposal closely to make sure they are not shortcutting process that may impact them and the state in the future.

b. A reasonable timeline for oil development depends on proximity to existing facilities. E.g.,

i. Tarn took around 2 years and was probably one of the fastest because it was near Kuparuk.

ii. 6 to 8 years is a better estimate for prospects that are within 25 miles of existing facilities.

iii. Around 10 years for projects that is more remote.

iv. These are rough rules of thumb that don't take in to consideration specific environmental, logistics, cultural and subsistence issues of a particular project - each of which could delay development for several years.

ACES incentives

1) Legacy fields and all other existing fields.
   a. Places a higher tax burden on them
   b. Takes away the TIE credits
   c. Ring fences certain credits.
2) Explorers
   a. Places a higher tax burden on them
   b. Gives them a guarantee of getting their tax credit giving them 2% to 3% extra on their transferrable credits
   c. Moves net operating losses to 25% carryover.
   d. The costs of the higher tax exceed the credit benefit.

Summary

Someone asked yesterday what the governor's economic policy should be regarding oil and gas.

I recommend a few things

1) Encourage heavy oil development; don't place penalties in front of it.
2) Work with Congress to get our fair share of OCS revenue before shell or any other oil company drills in the OCS.
3) Works with local communities to make sure their concerns are addressed before development proceeds and so that responsible development can proceed.