

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 86/2

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It seems appropriate for the state with the largest earthquakes and the greatest challenges in monitoring them. Of necessity, the State Seismologist has, from inception of the position, been physically co-located with net operations at UAFGI. However, the first incumbent was employed by DGGS as a consequence of DGGS's natural hazard responsibility. This caused some strain, as the State Seismologist was not available for informal discussions among DGGS staff and, for his part, felt that the strongly geologically oriented DGGS placed a low priority on seismic work. One of the disadvantages of partnering with other organizations is that the DGGS participant may be seen as "doing his/her own thing" by DGGS, particularly if the work is done off-site, however beneficial the work may be.

In 1986, there were substantial layoffs from state government due to a precipitous decline in oil revenue. Because positions within DGGS do not distinguish among types of geoscientists, the State Seismologist would have been "bumped" by more senior non-seismologists, eliminating seismology with DGGS even though both state and federal support for the seismic network continued. To accommodate this situation, funding was transferred to UAFGI and the State Seismologist was employed there in a non-tenure track, research faculty position. This change was formalized by modification of the relevant statute in 1987. The current State Seismologist is a Research Professor at UAFGI, and has an office in the UAFGI's Seismology Laboratory. This is logical from the standpoint of network operations, but has diminished DGGS' role in earthquake issues. A staff member of DGGS did serve on the UAFGI search committee when the current State Seismologist was sought and hired.

Justification

Alaska has experienced the second and third largest earthquakes on Earth this century, and will continue to be subject to violent and damaging seismic events. Although the Good Friday 1964 quake of south-central Alaska is famous, the fact that the Fairbanks region has had three magnitude 7 earthquakes in the past half century is less well known. Earthquakes affect all aspects of human activity in Alaska, and even relatively small events could have severe consequences in winter. Unique conditions in Alaska, such as extreme cold in winter and ice and glacial silt in soils, make the presence of local expertise especially important. Damaging consequences can be mitigated by planning growth and construction in a way that takes seismic risks into account. Monitoring of earthquakes, though not yet predictive in capability, permits rapid focusing of relief efforts. As a hazard that affects all of society, knowledge of the occurrence and mitigation of seismic hazards is clearly within the purview of DGGS.

Clients

The most important clients of the State Seismologist are the Office of the Governor and the Alaska Division of Emergency Services, who must be informed immediately of the occurrence, severity, and geographic extent of an earthquake disaster. In a crisis, delivery of medical services, shelter, food, and water, and maintenance of energy supplies are immediate concerns. In normal times, information on the location of active faults and unstable soils in earthquake-prone areas is very important to both public and private sector planners. The State Seismologist must coordinate his/her efforts with those of other networks operated under the national monitoring program, NEHRP, of the USGS. Finally, the network represents an extremely important research tool. Data from it must be readily available to the university community and to the scientific community outside the state. The data contain information on crustal and mantle structure and large-scale (tectonic) crustal plate motion that is of global significance.

Recommendations

The committee finds that the State Seismologist serves an important role that needs continued support from the state. The issue of the physical and administrative location of the Office resembles in some ways the issue of the location of DGGS as a whole. It should be noted, however, that history here and common practice in other states favors location of seismic net operations at the University. Other universities that

operate state- and federally-funded seismic nets include University of California at Berkeley, California Institute of Technology, University of Nevada at Reno, and the University of Washington. This reflects the importance of a state net as a research, as well as a monitoring tool and is probably a prerequisite for federal support. Given this and the fact that staff who maintain the net work for UAFGI, it seems logical that the State Seismologist position continue to be at UAFGI. Nevertheless, DGGS can still serve as a repository for seismic risk information and in an advisory capacity during earthquake crises. In addition, it should continue its efforts in engineering and geotechnical aspects of mitigating the problem. Ties between the State Seismologist and DGGS should be strengthened, at least by MOU spelling out areas of responsibility and mechanisms for cooperation, and perhaps, if administrative constraints permit, a joint appointment. However, a joint appointment between DGGS and UAFGI for the State Seismologist could be made only under conditions that do not permit a repetition of the "bumping" that occurred in 1986.

Expected Results

Although the office of the State Seismologist will remain at the UAFGI, the relationship between DGGS and the State Seismologist will be formalized in order to coordinate delivery of information on earthquake hazards and to respond collaboratively in an earthquake disaster.

PARTNERS, CLIENTS, AND FUNDING

Background

The issues of partners, clients, and funding are closely interwoven. The terms used in this report are as follows: A **partner** shares staff, funds, facilities, and logistics to attain a common goal and are other agencies or like-minded organizations, (i.e., U.S. Geological Survey, University of Alaska's Geophysical Institute, etc). A **client** is one who expects a product (usually specific). In the current fiscal climate, a client can be expected to pay for services and/or supply logistical support. Clients include other agencies, Native corporations, private industry, boroughs, public, and legislators. It is possible for an entity to be both a client and a partner.

Support may be in the form of money, shared office space, filing, and library systems, computer/telecommunications systems, helicopter and other forms of logistical support, and shared staff. These arrangements, some of which are currently more-or-less informally in place, can result in financial and personnel savings for both the long and short term.

Geological surveys in other states have found that they can significantly augment their direct state funding by pursuing pertinent timely programs with other state departments or divisions, federal agencies, local governments, and all facets of the private sector. These surveys are seeing increased success in raising funds through their clients and/or partners, for projects that address specific needs, save the state money, and supply needed baseline data that can be utilized in future programs. Presently nearly ten percent of the Washington state survey's total budget is derived from a single contract with Spokane County, for a water resources study. More than 90 percent of the Texas Bureau of Economic Geology's budget is derived from sources other than direct support. Other examples of the successful search for external funding include:

- ◆ Colorado--75 percent of total funding is from external sources
- ◆ Kansas--70 percent outside sources
- ◆ Nevada--50 percent of the funding is from external sources
- ◆ Idaho--outside funding constitutes 30-40 percent of the total expenditures
- ◆ Arizona--about 25 percent of total expenditures are non-state funds

Generally, these funds are used for operating expenses and to hire contract experts. The state core funding should cover salaries of permanent staff and facilities. This is something we can develop. The

committee recognizes that this does not happen overnight, for example, Kansas took 50 years to get 70 percent outside funding. To achieve this one must have continuity in planning and leadership, and persistent effort.

Justification

The development of strong and interactive client and partner relationship constitutes the foundation upon which the DGGS can increase its funding base and react in a timely manner to emerging problem areas or issues. In fact, such a cooperative network, with its attendant financial support, should allow the survey to become more proactive and more effectively anticipate the needs of both the public and private sectors.

Recommendations

Based on the examples which demonstrate the success other states have had in securing external funding, with sufficient planning and an entrepreneurial approach the DGGS should be able to raise, from external sources, a significant addition to its state derived expenditures.

One of the possible keys to successful long-term funding opportunities could be through a broad-based, cooperative approach involving several state departments working in concert to secure federal funds. Even with possible decreases in the level of direct federal aid to the states, there appears to be support for some type of block grant to help pay for programs previously financed by the federal government. Some of these grants could be designed for or directed toward long-term integrated projects which take a program from "the cradle to the grave"

The committee's recommendation is to aggressively pursue all viable sources of external funding and use those funds to support operating expenses and the use of contract expertise. The state core funding should be increased to pay salaries of permanent staff and facilities.

Expected Results

Programs that involve two or more state agencies or departments would be long term in nature, and proceed from acquisition of the basic geological and geophysical data, through the determination of the economic viability of the program, to the development and distribution of the final report or product. The program and its funding, which could be proportionately distributed to the various departments, could move from one department to another sequentially or simultaneously. Examples might be programs that (1) demonstrate the existence, quality, economic viability, development and distribution of coalbed methane as a cheaper fuel for an isolated interior village; (2) study of the existence of geohazards, their potential impact, design or monitoring programs, and development and evaluation of regulations concerning activities within the area of interest; or (3) baseline data for the Department of Environmental Conservation.

The committee strongly supports the idea of partnering and shared funding. An example of a highly successful partnering effort, the Alaska Volcano Observatory (AVO), has been included as an appendix to this report.

ADMINISTRATIVE LOCATION OF DGGS

Background

The DGGS was conceived and established to serve the State of Alaska. As discussed earlier in this report, its mission is to collect, evaluate, archive, and distribute geologic data and interpretive information on the state's energy and mineral resources, earthquake and volcanic hazards, and water quantity and quality. This information has historically served other state agencies, land managers, industry, the engineering community, and the general public.

Justification

DGGS is housed in the Department of Natural Resources because energy, minerals, and water are resources fundamental to the state's health and wealth. Geologic hazards profoundly affect the development and maintenance of the state's energy and mineral resources, communities and infrastructure, and the welfare of its people. Its location within DNR most directly connects DGGS with agencies and people who need the information DGGS can provide.

Recommendation

The committee has investigated various alternatives to the administrative location of DGGS within DNR by interviewing other state geological surveys in the United States that have various administrative relationships with their legislative, industrial, engineering, public, and academic communities. The committee considered these examples with special circumstances of Alaska's fundamentally resource-based economy. The viable alternatives are (1) remaining in DNR; (2) restructuring as an independent commission directly responsible to the governor and cabinet; and (3) becoming an adjunct to the university system.

As an independent commission answering to the governor, designation of priorities for the project work assigned to DGGS could swing radically from one administration to the next. Politics could have a very negative influence on the progress of projects, due to radical shifts in administrative policy or the whims of governors. In the long term, a stable environment allows greater efficiency and a faster response time to the great variety of political, economic, and public demands on DGGS for geologic expertise, analysis, and information. In view of a long term, stable environment, the committee concluded that an independent geologic commission would not be adequately insulated from political variations.

Within the university system, DGGS could perhaps retain a smaller core of scientists and still maintain scientific "critical mass" needed to accomplish multidisciplinary projects by drawing more heavily on the university geologic faculty and students. Other potential advantages include shared lab facilities and administrative costs, and enhanced scientific credentials and respect. This is a solution employed by several (15) other state geological surveys. The committee sees two main drawbacks to this solution.

First, within the university system, DGGS could very easily be too isolated from its clients and from a daily dialogue with partner agencies that would keep prioritization of its efforts on a steady course, relevant to the needs of its main clients. The university has not historically been a client of DGGS. Second, the exciting academic research environment of the university, and likely involvement with teaching and student advisory request and opportunities, although stimulating, would compete with the practical geologic project work that define the mission of DGGS. The threat of "academic isolation" is too real, and has traditionally been one of the main complaints about DGGS and other state and federal scientific agencies, even when they are not associated with universities. At present, located less than a mile from the university campus, the DGGS already enjoys the benefits of stimulating geologic interaction, student labor, and shared laboratory facilities.

It is the view of the committee that DGGS already has the best of both worlds: physical proximity to the university and administrative proximity to state government. Remaining within DNR would also protect DGGS from university politics. The university is addressing its own budgetary cutbacks and conserving energies for its teaching mission. Sharing people and resources that are already stretched too thin could strain relations within and between DGGS and the university. In the interest of long-term stability, independence from the university system would best serve DGGS and ultimately its clients.

Expected Results

DGGS should remain as a division within DNR. The Commissioner and state Advisory Board would continue to negotiate priorities and timeframes for projects undertaken by DGGS. The Commissioner, other agency leaders, and the State Geologist should coordinate DGGS project work with that of other agencies within DNR, and any other clients that require the expertise of DGGS.

STATE GEOLOGIST

Background

The State Geologist has a critical role in the scientific affairs of Alaska. The position carries the responsibility of knowledge of natural resources, geologic hazards, and current technologies available to the geoscience community. The position requires an individual that has strong leadership capabilities and the vision to guide the DGGS in its role as a responsible, proactive resource agency in the future.

One of the primary roles of the State Geologist is to secure adequate budgets for DGGS to preserve existing programs. As a result of recent budgetary degradation the DGGS is only able to provide low-level maintenance of high profile programs. However, opportunities do exist to obtain funding from non-traditional public and private sources.

Justification

Alaska is a significant repository of petroleum and mineral reserves, and coal and water resources and the state economy is strongly resource-based. The vast size and resource potential of the state combined with the extreme potential for geologic hazards dictates the need for a strong state geological survey. Due to the conditions presented the survey must be a very multi-faceted agency, likewise the individual filling the State Geologist position must have a very diverse background and be conversant in all aspects of the geology of Alaska.

Recommendations

The committee recommends that the position of State Geologist be filled without delay with a nationally recognized earth scientist noted for exceptional public vision and real knowledge of private resource industries. It is highly recommended the individual selected for the State Geologist has understanding of both state-level and federal political processes.

Because of the nature of the professionals within an agency such as DGGS, the State Geologist must have strong leadership qualities. The State Geologist must have the ability to be a strong manager and consensus builder for programs which may be unpopular from a strict scientific perspective. The individual selected for the State Geologist will be required to move the DGGS from traditional survey programs, such as regional mapping, toward projects that reflect new and changing public needs. The State Geologist should have the experience to predict shifts in resource industry requirements and public attitudes and awareness towards hazards and development and be one step ahead.

The new State Geologist must address new areas of funding potential such as partnering and cooperative agreements with both public agencies and private industry. Working with private industry and public agencies will be a primary function of the position.

Through the Geologic Mapping Advisory Board, the State Geologist should prioritize projects and staff them accordingly to assure quality products completed in a timely manner.

Candidates for State Geologist should be identified by a panel of scientists and citizens named by the Geologic Mapping Advisory Board. The constituent panel should forward their nominations to the Commissioner for final selection.

We recommend that the basic term be staggered across election year boundaries to provide continuity to DGGS. The position must also have sufficient tenure to be attractive to high quality individuals. Therefore, the committee proposes a five-year renewable term for the position.

Expected Results

The selection of a well-recognized, multidisciplinary earth scientist as State Geologist will provide DGGS with strong leadership to carry the agency forward into the next century. Results of this selection should conclude with the identification and appointment of an individual with capabilities to effectively address

- ◆ local legislature during budgetary hearings;
- ◆ other state agencies for cost-sharing programs;
- ◆ federal agencies for cost-sharing and cooperative agreement programs;
- ◆ and private industry for cooperative agreements.

STAFFING

Background

DGGS mission requires maintaining expertise in a variety of geologic disciplines to meet the state's needs with respect to identification and development of resources, monitoring, mitigation of hazards, land use, and regulation.

Justification

To accomplish the various missions of DGGS, there are several key staffing needs that must be provided for and maintained. These include:

- ◆ A variety of regional and topical expertise to identify, prioritize, propose, and execute projects through the Advisory Board and other agencies. The State Geologist will need input, support, and ideas from staff.
- ◆ The breadth and flexibility to evolve with changing scientific needs into the 21st century.
- ◆ The regional background and depth to identify the needed expertise for contracting on special projects (this includes both expertise in a discipline to recognize, for example, the need to contract an expert in magnetics or seismic interpretation for a specific data set *and* enough background in the field to know who are the experts to call).
- ◆ A sufficient number of professional scientists to cover:
 - main Alaska regions (north, central, south, southwest, and southeast);
 - main functions of DGGS (mapping, geochemistry, geophysics, mineral deposits, basin analysis, hydrology, seismic hazards, volcanic hazards, and environmental)
 - basic disciplines (igneous petrologist, metamorphic petrologist, sedimentary geologist/stratigrapher, structural geologist, surficial geologist, economic geologist, geochemist, and geophysicist).

The committee recognizes that a number of these specialties overlap.

Recommendations

The core staff size should remain relatively constant over at least the near term, roughly five years. Short-term changes in staffing can be accommodated by using temporary or contract employees, or involving

employees from other agencies in partnering arrangements. Proposed staffing levels and disciplines, based on the concept of two DGGS offices, in Fairbanks and Anchorage, are presented below.

Suggested staff allocation assigned to Anchorage would include the State Geologist, hydrologist(s), sedimentologist/stratigrapher, structural geologist/seismic geophysicist, GIS expert, and necessary administrative support staff. The remaining staff would be located in the Fairbanks office.

Over time, it would be highly desirable to reallocate personnel between the two offices on the basis of need and proximity to the principal client(s). As an example, it would be an advantage to ultimately have hydrogeologic capability in Fairbanks and mining geologists and an engineering geologist in Anchorage. Given a demonstrated need and additional sources of funding for DGGS these staffing changes could also be met by carefully managed additions to staff.

Expected Results

The location of the State Geologist and a small regional staff in Anchorage should greatly enhance the working relationships with both clients and partners. The level of financial support from both partners and clients should significantly increase, and new sources of revenue will eventually open up to the DGGS.

PHYSICAL LOCATION OF DGGS

Background

The main office of DGGS has been located in Fairbanks for most of its existence. At various times DGGS has also maintained offices in Anchorage and Juneau. Presently all DGGS employees are located in Fairbanks, except for the curator of the Geologic Materials Center in Eagle River. In the 1970s, the Fairbanks offices of DGGS were located in the O'Neill Building on the University of Alaska campus. An off-campus location was subsequently obtained at the university's request and to save costs. During the 1980s, several DGGS employees had offices in the DNR complex in Fairbanks. Currently all employees are located in office space about a half mile from campus and in Alaska Volcano Observatory office space at the Geophysical Institute.

This committee has weighed the benefits and disadvantages of the various past locations of DGGS offices and employees, and considered the effectiveness of DGGS in each situation. The most important factors relating to the effectiveness of DGGS in meeting its responsibilities to clients include communication and cooperation between DGGS, the Commissioner, and other state and federal agencies, communication and cooperation between DGGS and university faculty and students, access to university lab facilities and part-time student help, and access clients such as industry, engineers, Native corporations, and the public have to DGGS.

Justification

The Fairbanks location of DGGS has distinct advantages because of the Fairbanks' location of a large component of the state's mining community, access to the university, and a geographically central location. It has drawbacks with respect to interagency communication, although the State Geologist frequently travels to Anchorage and Juneau to meet with the Commissioner and other agency leaders, and also with respect to accessibility to the energy industry and the bulk of Alaska's population.

Clients

The main disadvantage of the Fairbanks location of DGGS is its inaccessibility to a range of clients. These clients are found within the energy industry, the remaining contingent of the mining industry, the

engineering community, and the hydrologic/environmental industry. These clients have significant geologic needs in southern Alaska.

One major user of geologic information is the energy industry, which is based in Anchorage. The Division of Oil and Gas, whose mission is predominantly regulatory, is located in Anchorage and for practical reasons acquires its own geological baseline information needed for energy-related regulatory decisions. DOG has competent geologists capable of meeting these needs. If this responsibility is removed from the purview of DGGS, there are dangers in that (1) DOG information is confidential and unavailable to other clients, and (2) data collection and analysis by a regulatory agency could have the appearance of being self-serving.

Another need for geologic expertise in southern Alaska arises from some of Alaska's most salient geologic hazards, earthquakes, and volcanoes, which are concentrated in the general vicinity of Anchorage. Much of the data collected for monitoring these hazards is processed at the Geophysical Institute on the University campus in Fairbanks, and the USGS maintains an observatory headquarters in Anchorage that works closely with UAF, USGS, and DGGS volcanologists in Fairbanks. The two parts of the Alaska Volcano Observatory coordinate a rapid response to eruptions. But emergencies aside, there is a larger need for geologists to provide information with respect to earthquake hazards that will affect structures and transportation systems in southern Alaska, for the engineering community and for public safety in general.

A growing concern in Alaska is water quantity and quality. Increasing population pressure, and long-ignored problems with disposal of hazardous materials on military bases have resulted in a dynamic hydrologic and environmental geologic industry that has a pressing need for baseline geologic and hydrologic information. In the 1980s, the water program was removed from DGGS and transferred to the Division of Mines and Water in DNR. However, this is primarily a regulatory agency, and as with DOG, there is always the problem of credibility when a regulatory agency collects and maintains its own baseline data. In another section of this report, the committee recommends that water information functions should be returned to the mission of DGGS. A large component of the hydrologic/environmental industry and the mining and water regulatory agency are located in Anchorage, and expertise in Fairbanks at DGGS is not adequately accessible to Anchorage-based clients of DGGS. In addition, the USGS Water Resources Division has its main offices in Anchorage, and coordination would be mutually beneficial.

Recommendation

The committee recognizes clear advantages to the location of DGGS in Fairbanks near the university campus. These advantages include accessibility to DGGS for the large Fairbanks-based mining industry, access to university facilities and scientists for DGGS, and a location geographically centered in the state. There is also a demonstrated need for geologic expertise in DGGS in Fairbanks to address hydrologic and environmental problems in northern Alaska, particularly now with the recent development of mineral properties in the Fairbanks and Circle mining districts.

The committee also recognizes an unfulfilled need for DGGS to have a presence in Anchorage to deal with a larger, and growing client base in southern Alaska. A presence in Juneau for southeastern Alaska is also warranted, but is seen to be a luxury in the present fiscal climate. The committee recommends that DGGS maintain offices in both Anchorage and Fairbanks.

There are obvious budgetary concerns with this recommendation. The Fairbanks office is perceived to be understaffed to meet its project responsibilities and can not afford to lose scientists by transfer to Anchorage. In addition, DNR can not afford a major staff increase in this time of diminishing funds. An attractive possibility is to move a few geologists from the Division of Mining and Water Management and the Division of Oil and Gas who are already located in Anchorage over to DGGS and to replace the few recently retired geologists from Fairbanks with new hires in Anchorage. To minimize the understaffing

problem, it would be most efficient to split along disciplinary lines with energy and water focused in Anchorage.

Because the Commissioner, most other state and federal agency leaders, and the greater proportion of DGGs clients in industry, transportation, and the public are in Anchorage, we have already recommended that the most logical and efficient residence for the State Geologist is Anchorage. It is anticipated that the State Geologist will need to meet with, generate proposals to, and respond to this large and diverse group of partners and clients on a daily basis. The State Geologist will obviously need a strong deputy in Fairbanks, and will need to visit Fairbanks on a regular basis.

The location of the DGGs office in Fairbanks has risen as a subject of debate. There is an opportunity for DGGs to move to a planned new wing of the Geophysical Institute on the university campus. There are clear scientific advantages to being housed with other geologists and in the same building with lab facilities. This location would also somewhat alleviate the feeling of isolation within DGGs because they would be surrounded with university scientists. However, DGGs has had offices on campus several times in the past, and there have been problems that ultimately resulted in moving back off campus. The present location, less than a mile from campus allows proximity to university scientists and insulation from university politics, including unpredictable fee structures developing from university budget variations. Any future space-sharing agreement with UAF should take these past problems into account. Another alternative would be to move DGGs in the DNR complex in Fairbanks. This would be advantageous for cooperation and collaboration with other state agencies, but would probably result in less communication with the university scientists because of the physical separation. Although it is extremely important for the State Geologist to interact with other state agency leaders, that will happen in Anchorage, and the individual scientists will benefit more from proximity to university facilities and student labor. The committee suggests that the present location of the DGGs offices in Fairbanks is a good compromise.

The optimum location of the Anchorage component of DGGs will also be a compromise between scientific advantages and political necessities. The committee concludes that it is essential for the State Geologist to be in close contact with the Commissioner and other state agencies, which translates to finding space near the other DNR agencies in the Frontier Building. This would also maintain accessibility of the regulatory agencies to water and energy scientists. An alternative would be office space adjacent to the USGS offices on the Alaska Pacific University campus, which would facilitate collaboration with USGS hydrologists, surficial geologists working on earthquake hazards, and geologists in the Alaska Volcano Observatory. University politics are less of a threat on the APU campus because it is very small and university politics are consequently smaller scale. APU acts simply as a landlord to the USGS. There is a geology faculty of one, and although USGS scientists occasionally provide a lecture, there have been no students available for help.

Expected Results

With a presence in Anchorage DGGs will more easily interface with other state agencies, will be more accessible to industry and the public in southern Alaska, and will have stronger collaboration with the USGS in building a hydrologic database across the state. The location of the State Geologist in Anchorage is anticipated to increase exposure and access to funding-opportunities both within and outside of state government.

APPENDIX

EXAMPLE OF PARTNERING

Background

The Alaska Volcano Observatory (AVO) is a cooperative organization that uses federal, state, and university resources to monitor Alaska's hazardous volcanoes, predict and record eruptive activity, and implement public safety measures. AVO focuses on volcanoes in the Cook Inlet region, Alaska's most populous area and one important for international air transportation, oil and gas production, commercial fishing and tourism. Eruptions of three volcanoes in this region have significantly impacted human activities in each of the past five decades. The program also monitors other Alaskan volcanic areas because of their potential for catastrophic events or as a guide to Cook Inlet volcanism. AVO is a joint program of the U.S. Geological Survey, Geophysical Institute of the University of Alaska Fairbanks, and the State of Alaska Division of Geological & Geophysical Surveys. Components of the program are:

1. Monitoring, principally with a seismic network but supplemented as needed through geodesy, slow scan TV, satellite, geochemical, hydrologic and spectroscopic observations, to detect eruptive precursors and to track and record ongoing eruptions.
2. Communication to disseminate public safety information. This component involves general education concerning volcanic hazards as well and timely warnings of impending eruptions and the areas these eruptions will impact.
3. Basic geological, geochemical, and geophysical investigations to determine the history, physical characteristics, and eruptive mechanisms of Alaska volcanic systems, as a guide to future activity.

Justification

Alaska's Aleutian volcanic arc contains more than 50 geologically young and potentially explosive volcanic centers. Together, these have erupted once or twice each year since the turn of the century. In addition, more than 20 catastrophic caldera-forming eruptions have occurred in the past 10,000 years. The most recent of these was the great eruption of 1912 near Mt. Katmai on the Alaska Peninsula in what is now Katmai National Park. Approximately 30 km³ of pumice and ash were erupted in 60 hours, filling a large glacial valley with up to 200 m of ignimbrite and dumping 30 cm (when fully compacted) of ash on Kodiak, 160 km down wind. The event was accompanied by floods, mud flows, magnitude 6 earthquakes, and the collapse of Mt. Katmai to form a 3-km-diameter, 1-km-deep caldera. This remains the largest eruption of this century on Earth, but numerous young caldera structures elsewhere in the arc show that its size is not without precedent here. With a record of unnumbered "average" eruptions and several truly world-class events in the Holocene, the Aleutian arc is clearly the most dangerous area in the nation with respect to explosive volcanism, and one of the most important such regions in the world.

Hazards associated with explosive volcanism take many forms. The most direct are the explosions themselves. Eruption clouds most often rise vertically above the vent, but they may be laterally directed as well. Ballistic ejecta pose a hazard to aircraft and buildings within a few kilometers, sometimes farther if the blast is directed. Hot, fast moving pyroclastic flows can reach out along valley floors many kilometers from the eruptive center. Usually more far-reaching are the consequences of ash falls from the eruptive plumes, which can make air and surface travel impossible and, in major eruptions, cause buildings to collapse. Perhaps of equal seriousness in Alaska is the presence of water and ice on and around active volcanoes. Eruptions cause catastrophic melting of glacial ice generating mud flows which can travel tens of kilometers. Volcanic cones, over-steepened by eruptive or intrusive activity, can undergo sector collapse. Debris flows thus generated will, if they enter the sea, cause tsunamis and attendant widespread devastation along shorelines.

Alaska is sparsely populated, and so the potential for near-field damage is low in most cases. There is however, a high potential for repeated disruption of air traffic, oil and gas production, commercial fishing, tourism, and military operations due to ash plumes and falls, and far-reaching mud flows and tsunamis. This threat is most serious in the Cook Inlet region, where Alaska's population is concentrated. Augustine is the most active of the Cook Inlet centers, with 6 explosive eruptions this century. In 1883, a volcanic debris flow shed by Augustine entered the sea, apparently triggering a tsunami that inundated the harbor of English Bay on the lower Kenai Peninsula. This type of activity remains a serious threat to coastal Kenai communities. The most recent of Augustine eruption closed businesses in Anchorage and halted transportation throughout southern Alaska in March and April of 1986. An eruption of Spurr in 1953 caused significant ash falls in Anchorage. In 1989-1990, the explosive eruptions and associated mud flows of Redoubt volcano disrupted air travel, caused nearly \$100 million of damage to aircraft, and required \$20 million of preventive measures at a neighboring oil terminal. Mount Spurr erupted again in 1992, dusting Anchorage with ash and causing the airport to be shut down for a day. These were modest eruptions by Aleutian arc standards, but Cook Inlet has reached the level of development where even a small eruption can have major consequences. Meanwhile, traffic on North Pacific air routes has grown to the point where about 10,000 passengers per day transit the Aleutian Arc. Some 70 percent of cargo between eastern Asia and the United States is landed at Anchorage, which has become the first-ranked freight airport in North America. All that is required for a lethal accident is an ash cloud to reach 30,000 to 40,000 feet above one of these volcanoes undetected.

History of Development of AVO

Volcanology in Alaska can be regarded as beginning with the great eruption of 1912. The burial of the village of Kodiak under a thick blanket of ash, all the more disturbing to the inhabitants because they did not regard themselves as being near a volcano, triggered a four-year search for the eruptive vent on the remote Alaska Peninsula. That search, funded by the National Geographic Society and led by Robert Griggs, discovered the Valley of Ten Thousand Smokes and initiated debates and inquiries that have become themes in modern volcanology. However, volcanology was not extensively practiced by Alaskans until modern-style investigations of the Aleutian Arc were begun in the 1960s and 70s by UAFGI, the branch of Alaskan Geology of the USGS, and DGGs. Motivations for all three organizations included basic research, volcano hazards, and geothermal energy. The UAFGI and USGS work had a substantial basic research component, whereas DGGs efforts emphasized a statewide survey of geothermal resources. DGGs conducted detailed studies of Redoubt, Makushin, Geyser Bight, Akutan, and Spurr magma/hydrothermal systems and undertook monitoring of the fumaroles at Cook Inlet volcanoes. Much of the DGGs effort was funded by the U.S. Department of Energy. UAFGI and USGS established limited volcano seismic networks for monitoring purposes. In 1982, the Workshop on Alaskan Seismology organized by DGGs formally called for the establishment of a research consortium to coordinate and strengthen these activities for the Cook Inlet region. Although Alaskan scientists worked toward this goal, it remained for Augustine Volcano to bring their efforts to fruition. In response to the disruption of commerce caused by the 1986 Augustine eruption and in consultation with Alaskan scientific leaders, members of the Alaskan congressional delegation asked the USGS to outline requirements for a volcano observatory, incorporating existing USGS, UAF, and DGGs facilities and expertise. As a result, the Alaska Volcano Observatory (AVO) was established in 1988 as a joint program of the USGS, UAFGI, and DGGs, under a Memorandum of Understanding signed by the Chief Geologist of the USGS, the Director of UAFGI, and the State Geologist. The \$500K/year federal contribution was an annual Congressional add-on to the USGS budget and was adequate only for minimal geophysical monitoring of the Cook Inlet volcanoes.

The original concept was to monitor Augustine, however the mission was soon broadened to include Augustine's neighbors. This was fortunate, because Redoubt Volcano burst into eruption on December 14, 1989, only two months after Redoubt's seismic network was placed on line. The precursor seismic activity, which preceded the eruption by only 24 hours, was successfully detected, with appropriate warnings issued.

Under these emergency conditions, AVO's level of effort was rapidly expanded from its modest base to encompass monitoring of gas, tephra, eruption-caused lightning, and floods as well as visual monitoring by slow-scan TV and satellite. Warnings were issued prior to the major eruptive events of January 2, March 23, and April 6. Of special note was the use of meteorological data to predict plume trajectories and the timely evacuation of personnel from the Drift River Oil Terminal prior to a major debris flow.

The number and severity of explosive eruptions at Redoubt required a labor-intensive response, for which several million dollars in federal funds were made available. Two AVO centers evolved. One in Anchorage was staffed by the USGS, directed most field operations, and interfaced with federal agencies and concerned commercial enterprises (aviation, oil and gas). The center in Fairbanks, located at the Seismology Laboratory of UAFGI, was staffed by UAFGI, USGS, and DGGS personnel. It focused on real-time acquisition and interpretation of seismic data, and interfaced with state agencies. Two DGGS personnel were "drafted" early in the crisis, one to provide volcanological expertise and the other to help run the then-overloaded computer system. Their time was covered through a combination of state supplemental and emergency federal funds. Following the eruption, federal funding of AVO dropped from a peak of \$6 million/year to \$3 million/year. State support of communications, volcano work within the Seismology Laboratory, and part of the time of DGGS personnel totaled about \$500K/year.

The next crisis, the Mount Spurr eruptions of 1992, was also successfully predicted by AVO. Because of fewer explosions and consequently less disruption than Redoubt, Spurr activity brought no new federal dollars, but did help AVO to become a permanent, USGS-budgeted part of the Volcano Hazards Program. The state provided \$300 k in emergency funds through the Division of Emergency Services to UAFGI to defray the cost of replacing eruption-damaged equipment, greatly increased helicopter time, and maintaining 24 hour/day operation. At this writing, the approximate funding levels of \$3 M from USGS and \$0.5 M from the state continue. Federal support may increase to accommodate monitoring of Alaska Peninsula and Aleutian Islands volcanoes. DGGS now contributes 18 person-months per year to AVO, for which it is reimbursed for 13 months by the USGS.

Discussion

AVO exemplifies the type of partnering that can enhance the effectiveness of a government program and eliminate wasteful duplication. This approach respects the historical role that the USGS, UAF, and DGGS have played in volcanological studies, and combines the perspectives, missions, and strengths of these organizations. The USGS is the federal agency with primary responsibility for warning of volcanic and hydrologic hazards in the US (Disaster Relief Act of 1974). The USGS has extensive experience in volcano monitoring and the management of observatories, and in times of crisis can draw on its substantial resources of expertise outside the state, including scientists from its Cascades of Hawaiian observatories and its center at Menlo Park, California. The DGGS has a similar mandate for hazard mitigation within the state and possesses important expertise in acquisition and management of state geologic and geophysical data. More than the other organizations, it provides the Alaskan perspective within AVO. As an educational and research institution, UAFGI brings a tradition of productive research and also provides a route for student involvement in AVO. This is cost-effective for AVO operations and represents an exceptional scientific opportunity for students. This partnership is also important from a political standpoint. It is a matter of significance to legislators in Juneau that support for DGGS and UAF augments a significant federal effort within the state, and it is of importance to Congress that the State of Alaska takes volcano hazards seriously and contributes to the monitoring effort. The appropriate proportions of state and federal support are difficult to quantify. More important is that both entities acknowledge through their support that volcano hazards in Alaska have an impact at both the local and national levels.

Although the need for partnering in the form of AVO was recognized in 1982, it did not occur until propelled by the dual forces of crisis and new money. The challenge for the future of DGGS will be to

develop partnerships without such forces, but where the only incentive is increased effectiveness in accomplishing the DGGs mission. To do this, partnering must be seen by both employees and management as a good thing. In general, partnering will require some base of state support; it leverages state support rather than replacing it. A special effort must be made to maintain contact between DGGs and DGGs employees who are stationed at partner institutions. Finally, personal initiative in obtaining outside funds should be seen as increasing job security and flexibility, rather than decreasing security by reliance on outside "soft" money.

(7)

HOUSE COMMITTEE REPC...I

Date Referred to Committee: January 8, 1996

FURTHER REFERRALS:

Resources
FinanceDate of Committee Action: 1/25/96The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered:EO 92

EXECUTIVE ORDER NO. 92

Transferring duties in the Department of Natural Resources to consolidate the division of oil and gas and the division of geological and geophysical surveys into a division of oil, gas, and geology in that department.

recommends it be replaced [] the same title
with the following committee substitute [] a new title

[] additional referral to _____ Committee
[] attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept)

APPROVES PREVIOUS: (Dept/Date)

[X] fiscal note(s) ONE

[] fiscal note(s) _____

[] zero fiscal note(s) _____[] zero fiscal note(s) _____

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<i>[Signature]</i>			✓	
<i>[Signature]</i>			✓	
<i>[Signature]</i>			✓	
<i>[Signature]</i>			✓	

CHAIR'S SIGNATURE

[Signature]

1-25-96



Official Business

Alaska State Legislature

HOUSE OF REPRESENTATIVES

House Special Committee On Oil & Gas

State Capitol
Juneau, AK 99801-1182

MEMORANDUM

DATE: February 2, 1996

TO: Representative Joe Green, Co-Chairman
Representative Bill Williams, Co-Chairman
House Resources Committee

FROM: Representative Norman Rokeberg, Chairman
House Special Committee on Oil & Gas

SUBJECT: Executive Order No. 92

A handwritten signature in dark ink, appearing to read 'N. Rokeberg'.

Executive Order No. 92 consolidates the Division of Oil and Gas with the Division of Geological and Geophysical Surveys located within the Department of Natural Resources. The testimony before the House Special Committee on Oil & Gas indicated that there is no consensus regarding whether the consolidation outlined in Executive Order No. 92 is the correct configuration of the two divisions.

Remarks during public testimony indicates there are both good and bad consequences if the consolidation goes forward. As a result of committee testimony, the members of the committee voted to introduce a special resolution to oppose the consolidation in order to expedite the process and move the executive order to the appropriate authorized committee.

In addition we checked with Legislative Legal on the proper procedure for handling a resolution opposing an executive order. The legal memorandum we received stated that under Uniform Rule 21 joint standing committees must consider executive orders.

9-LS1576A ✓
Cook
1/23/96

HOUSE SPECIAL CONCURRENT RESOLUTION NO.
IN THE LEGISLATURE OF THE STATE OF ALASKA
NINETEENTH LEGISLATURE - SECOND SESSION

BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Introduced:
Referred:

A RESOLUTION

1 **Disapproving Executive Order No. 92.**

2 **BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

3 **WHEREAS** the governor, under authority of art. III, sec. 23, Constitution of the State
4 of Alaska, has proposed in Executive Order No. 92 to combine the functions of the division of
5 oil and gas and the division of geological and geophysical surveys into a division of oil, gas,
6 and geology; and

7 **WHEREAS** art. III, sec. 23, Constitution of the State of Alaska, provides that unless
8 disapproved within 60 days of a regular session by resolution concurred in by a majority of the
9 members of the legislature in joint session, an executive order becomes effective at a date
10 designated by the governor;

11 **BE IT RESOLVED** by the Alaska State Legislature that Executive Order No. 92 is
12 disapproved.

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES LEGISLATIVE AFFAIRS AGENCY STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

130 Seward Street, Suite 409
Juneau, Alaska 99801-2105

MEMORANDUM

January 23, 1996

SUBJECT: Procedure for Disapproving an Executive Order
(Work Order No. 9-LS1576)

TO: Representative Norman Rokeberg
Chair, House Oil & Gas Committee

FROM: Tamara Brandt Cook
Director

You have asked what the procedure is for the disapproval of an executive order. The state constitution contains the requirement that disapproval of an executive order is accomplished "... by resolution concurred in by a majority of the members in joint session ..." (Article III, Section 23) This must be complied with or any attempt by the legislature to disapprove an executive order will be held invalid by the court.

In addition to the procedure set out in the constitution, Uniform Rule 49(a)(4) provides

A special concurrent resolution is employed to consider disapproval of an executive order of the governor laid before the legislature under provisions of Sec. 23, Art. III, of the State Constitution. This resolution must be considered by a joint committee and may be adopted by a majority vote of the full membership of the legislature in joint session without recourse to three readings.

So, the uniform rule adds the requirement that a joint committee consider each special concurrent resolution before it is adopted in joint session. Clearly, a joint committee could be established under Uniform Rule 21 for the purpose of considering a resolution disapproving an executive order. However, it has been the position of this office since at least 1981 that, because Uniform Rule 49(a)(4) does not specifically require the establishment of a joint committee under Rule 21, two standing committees meeting jointly would fulfill the requirement of consideration by a joint committee. This is what has been done in the past, and I cannot find an example within the past 15 years of the legislature appointing a joint committee to consider a resolution disapproving an executive order.

Any member or committee may, of course, introduce a special concurrent resolution disapproving an executive order. After the resolution and the executive order itself have

Representative Norman Rokeberg

January 23, 1996

Page 2

been reported from committee, a joint session must be either agreed to by the presiding officers or called by a house under Uniform Rule 51 for the purpose of considering the special concurrent resolution disapproving the executive order.

TBC:pl:klb

96-030.plm

WORK ORDER REQUEST FORM

W.O. [19] LS-1576

KEYWORDS: EXECUTIVE ORDER

ASSIGNED: Cook

REQUEST FOR: Resolution

TAKEN BY: Cook

SUBJECT: Disapproving E.O. 92

REQUESTED FOR: HC HO&G

BY: Shirley

PHONE: 465-4968

DELIVER TO: Rep. Rokeberg, Cap. 110

INSTRUCTIONS: Draft resolution disapproving E.O. 92.

OBTAIN

SPECIAL DRAFTING INSTRUCTIONS ATTACHED []
AUTHORIZED TO CONFER WITH _____

RETURN _____

_____ TO REQUESTOR

APPROVED: X DIRECTOR, LEGAL SERVICES

REVIEWED _____

IN 01/22/96 DUE _____

TYPED: Draft _____ Date _____

Final _____ Date _____

PROOFED _____ DELIVERED _____

SPECIAL INSTRUCTIONS to TYPING/PROOFING
Memo explaining procedure for reject-
ing E.O.

Request for DRAFT



HOUSE SPECIAL COMMITTEE ON
OIL AND GAS

DATE: 1/25/96

SIGN - IN

Subject of meeting:

EO 92: Consolidation of the Division of Oil and Gas with the Division of Geological and Geophysical Surveys

PLEASE PRINT!
NAME

ADDRESS (MAILING) & (ZIP)

PHONE

REPRESENTING

**DO YOU WANT
TO TESTIFY?**

[illegible]

Sec. 41.08.010. Division of geological and geophysical surveys. There is established in the department a division of geological and geophysical surveys under the direction of the state geologist. (§ 1 ch 93 SLA 1972)

Sec. 41.08.015. State geologist. The commissioner shall appoint the state geologist, who must be qualified by education and experience to direct the activities of the division. (§ 1 ch 93 SLA 1972)

Sec. 41.08.017. Hydrological and seismic hazard data declared to be of public interest. (a) Systematic collection, recording, evaluation, and distribution of data on the quantity, location, and quality of water of the state in the ground, on the surface of the ground, or along the coasts, are in the public interest and necessary to the orderly domestic and industrial development of the state.

(b) Systematic collection, evaluation, archival, and distribution of geologic data and information on earthquakes, volcanic eruptions, and engineering geology and identification of potential seismic, volcanic, and other geological hazards throughout the state are in the public interest and necessary to orderly, safely, and cost-effective development in the state. (§ 1 ch 41 SLA 1977; am § 1 ch 101 SLA 1983; am § 3 ch 36 SLA 1987)

Sec. 41.08.020. Powers and duties. (a) The state geologist shall conduct geological and geophysical surveys to determine the potential of Alaskan land for production of metals, minerals, fuels, and geothermal resources; the locations and supplies of groundwater and construction materials; the potential geologic hazards to buildings, roads, bridges, and other installations and structures; and shall conduct such other surveys and investigations as will advance knowledge of the geology of the state. With the approval of the commissioner, the state geologist may acquire, by gift or purchase, geological and geophysical reports, surveys, and similar information.

(b) In addition, the division of geological and geophysical surveys shall:

(1) collect, record, evaluate, and distribute data on the quantity, quality, and location of underground, surface, and coastal water of the state;

(2) publish or have published data on the water of the state;

(3) require the filing with it of the results and findings of surveys of water quality, quantity, and location;

(4) require of water well contractors, the filing with it of basic water and aquifer data normally obtained, including but not limited to well location, estimated elevation, well driller's logs, pumping tests and flow measurements, and water quality determinations;

(5) accept and spend funds for the purposes of this section, AS 41.08.017, and 41.08.035 and enter into agreements with individuals, public or private agencies, communities, private industry, state agencies, and agencies of the federal government;

(6) collect, evaluate, and distribute geologic data on seismic events and engineering geology of the state;

(7) identify potential seismic hazards that might affect development in the state;

(8) inform public officials and industry about potential seismic hazards that might affect development in the state. (§ 1 ch 93 SLA 1972; am § 2 ch 41 SLA 1977; am § 7 ch 175 SLA 1980; am § 2 ch 101 SLA 1983; am § 4 ch 36 SLA 1987)

Cross references. — For declaration of sources, see § 1, ch. 175, SLA 1980, in the legislative policy on geothermal re- Temporary and Special Acts

Sec. 41.08.025. Accounting and disposition of receipts. Repealed, § 28 ch 90 SLA 1991. For current law, see AS 37.05.142 — 37.05.144.]

Sec. 41.08.030. Printing and distribution of reports. The state geologist shall print and publish an annual report and such other special and topical reports and maps as may be desirable for the benefit of the state, including the printing or reprinting of reports and maps made by other persons or agencies, where authorization to do so is obtained. Reports and maps may be sold and all money received from these sales shall be paid into the general fund. (§ 1 ch 93 SLA 1972)

Sec. 41.08.035. Regulations. The department may adopt regulations relating to and providing for the systematic collection, recording, and distribution of data on the water of the state. (§ 3 ch 41 SLA 1977)

Sec. 41.08.040. Cooperation with other agencies. The state geologist, with the consent of the commissioner, may enter into cooperative agreements with federal, state, and local governmental agencies to perform geological and geophysical surveys, studies, investigations, and services. (§ 1 ch 93 SLA 1972)

SCOMM

96:8

HB 207

Legislative Research Agency

Alaska State Legislature



130 Seward Street, Suite 213
Juneau, Alaska 99801-2196

Phone: (907) 465-3991
Fax: (907) 463-3351

February 14, 1995

MEMORANDUM

TO: Representative Joe Green

FROM: Gordon S. Harrison, Director 

RE: Oil and Gas Incentive Programs
Research Request 95.072

You asked for information on state statutory provisions designed to provide an incentive for companies to explore for, develop, and produce oil and gas resources in Alaska. Specifically, you asked for a report that includes "analysis of which incentives have been used, and why, along with analysis of why the others have not been used; and any and all memoranda, findings of fact, or written determinations related to any approval or rejection of an application by a producer to use one of the incentive programs." This memorandum describes the major statutory incentives and presents basic information on their use. We obtained the information primarily from the administrators of the incentive programs. Included is a documentary record of all denials by the Department of Natural Resources of applications for the benefits of an incentive provision. This documentary record, with an accompanying letter, was provided by Jim Eason, outgoing director of the Division of Oil and Gas. We have had neither the time nor staff resources to undertake an independent assessment of the reasons why companies have used or not used the various incentives. Presumably companies have sought the benefit of an incentive when they thought their projects met the basic statutory criteria for eligibility. Whether the state agencies administering the incentives have unreasonably impeded access to them, or the incentives themselves are inherently ineffective in stimulating oil and gas projects, are questions beyond the scope of this memorandum.

Statutory oil and gas incentives and incentive programs involving exploration and royalties are administered by the Department of Natural Resources (DNR). Incentives involving taxes are administered by the Department of Revenue (DOR).

Tax Incentives Administered by the Department of Revenue

Two major tax incentives for oil and gas projects are administered by DOR: the economic limit factor (ELF) and the enhanced oil recovery (EOR) tax credit. Until December 31, 1994, when the provision died by way of an automatic "sunset" clause, the department also administered a special industrial investment tax credit for gas processing facilities and mineral developments.

Economic Limit Factor (ELF)

In Alaska, the nominal severance (production) tax rate on oil and gas is 15 percent of the gross value at the point of production, except for properties initially coming into commercial production after June 30, 1981, which pay 12.25 percent for the first five years of production. Under AS 43.55.013, these nominal rates are multiplied by a factor that varies from 0 to 1 depending upon the productivity of wells in the field and the overall productivity of the field. This factor is the ELF, and it is derived from a complex formula that includes the average number of barrels produced daily by each well, and the number of barrels produced daily by the entire field. If, for example, the ELF calculation results in a factor of .6 on a field paying a nominal severance tax of 15 percent, the effective tax rate is 9 percent. The accompanying table shows the average daily production, the nominal tax rate, the ELF, and the effective tax rate for all producing oil fields in Alaska for calendar year 1994.

The ELF derives its name from a basic purpose of the provision: it is intended to prolong production from a declining field by reducing the tax burden as the field approaches its "economic limit," which is the point at which operating costs (including taxes) equal gross revenue. However, because the ELF comes into play well before a field is in the vicinity of its economic limit, it does more than merely prevent the premature shutdown of a field. It also imparts to the basic severance tax structure a progressive character. That is, it produces a higher tax on larger fields, which are presumably more lucrative, and a lower tax on smaller fields, which are presumably more of a marginal economic proposition. In this respect it mimics in an imperfect but general way a tax on income, which economists usually consider to be the most efficient form of taxation. Therefore, the ELF is a basic feature of the state's severance tax structure, rather than an addendum designed to provide a special incentive. Nonetheless, the ELF creates a particularly strong set of economic incentives for the oil and gas industry, and for that reason it is included in this overview.

DAILY GROSS PRODUCTION and SEVERANCE TAX RATES for ALASKA OIL FIELDS CALENDAR YEAR 1994				
FIELD	Daily Gross Production (bbls)	Nominal Severance Tax Rate (%)	Average Economic Limit Factor (ELF)	Effective Severance Tax Rate (%)
NORTH SLOPE				
Prudhoe Bay	971,000	15.00	.986	14.79
Kuparuk	305,400	15.00	.864	12.96
Pt. McIntyre	100,600	12.25	.907	11.11
Endicott	90,400	15.00	.751	11.26
Lisburne	19,200	15.00	.000	0.00
Milne Point	12,200	15.00	.006	0.08
Niakuk	9,000	15.00	.035	0.53
Schrader Bluff	2,900	15.00	.000	0.00
North Prudhoe Bay	2,300	12.25	.000	0.00
West Beach	1,500	12.25	.000	0.00
Sag Delta	900	12.25	.000	0.00
COOK INLET				
McArthur River	36,300	15.00	.000	0.00
Middle Ground School	6,700	15.00	.000	0.00
Granite Point	6,000	15.00	.000	0.00
Swanson River	4,400	15.00	.000	0.00
West McArthur River	2,400	15.00	.000	0.00
Trading Bay	2,100	15.00	.000	0.00
Beaver Creek	400	15.00	.000	0.00

Source: Department of Revenue

The table shows that only large North Slope fields pay a significance severance tax: in 1994, production from the Prudhoe Bay field was taxed at an effective rate of 14.79 percent; Kuparuk at an effective rate of 12.96 percent; Endicott at an effective rate of 11.26 percent; and Pt. McIntyre at an effective rate of 11.11 percent. Two smaller fields paid virtually no severance tax in 1994: Milne Point production paid an effective severance tax of 0.08 percent, and Schrader Bluff production paid an effective rate of 0.53 percent. The other twelve producing fields paid no severance tax. Clearly the ELF creates an incentive for oil companies to explore for and develop small pools of oil in the vicinity of existing oil production infrastructure, such as around Prudhoe Bay and Cook Inlet. More generally, the progressive nature of the severance tax created by the ELF reinforces this favoritism of small fields (i.e., those with production under 150,000 bbls/day). While large and prolific fields pay a comparatively high tax, these fields are presumed to be sufficiently robust to bear the burden of the tax¹.

Application of the ELF formula is automatic—that is, it does not depend on a discretionary decision of the commissioner. Taxpayers determine their tax liability on the basis of production statistics which are reported to the state. Returns filed by taxpayers are subject to audit by DOR.

Enhanced Oil Recovery (EOR) Credit

To encourage oil production from declining fields in the United States, Congress in 1990 authorized a 15 percent federal income tax credit for the cost of tertiary EOR projects (Title 26 U.S.C. 43). The federal code is adopted by reference in Alaska's corporate income tax law (AS 43.20.021). To qualify for the credit, a tertiary EOR project must begin after December 31, 1990, and it must significantly increase the ultimate amount of crude oil recovered from a drilling operation located in the United States. Taxpayers take the state credit when they submit their corporate income tax return to DOR. The department is prevented by confidentiality statutes from revealing information about individual tax returns, and it therefore may disclose only aggregate data (and this only to the extent that the number of taxpayers is large enough to conceal the tax payment of an individual company). According to the Alaska DOR, for tax years 1991 through 1993, at least \$21 million in credits were claimed on initial tax returns. These returns are subject to audit.

¹Future production from the West Sak field may present an exception, as costs there are expected to be inordinately high. However, the ELF formula is sensitive to two threshold values--300 bbls/day/well and 150,000 bbls/day/field--so it is difficult to predict how the formula will work for this field in the absence of actual well and field production statistics.

Special Industrial Incentive Investment Tax (Expired)

In 1984 the Alaska Legislature created a special credit against a company's state corporate income tax for investments made after December 31, 1984 in a "gas processing project" and in "exploration, drilling of wells, development, or mining of minerals or other natural resources ... other than sand or gravel." The original legislation (Chapter 60 SLA 1984) prohibited credits on investments made after December 31, 1994, although it allowed unused credits to be carried forward through 1999. Thus, this provision expired at the end of last year. The department would not provide an estimate of the value of credits taken and would say only that "several corporations" took the credit during the last decade for projects that include an oil and gas production project in Cook Inlet and several natural gas and gas liquids projects on the North Slope. According to Bob Bartholomew, Deputy Director of the Division of Income and Excise Audit, DOR, the credit was not claimed for any non-oil and gas mining projects.

Exploration and Royalty Incentives Administered by Department of Natural Resources

State law authorizes the commissioner of DNR to include certain exploration incentives in state oil and gas leases, and to approve a reduction of the royalty terms of an oil and gas lease under certain circumstances. The discretionary character of these statutory programs, which require the commissioner to make a determination of the state's best interest before offering or approving a benefit, differentiate them from the incentive programs under the purview of DOR, which are self-executing. Statutory provisions for reducing royalties have changed over the years; however, repealed provisions may still be "alive" in active leases issued when the provisions were current, and they therefore remain relevant today.

Below is a brief discussion of exploration and royalty reduction provisions. Additional discussion and pertinent records submitted by Mr. Eason follows as an attachment.

Royalty Reduction Provisions

Currently, AS 38.05.180(j) authorizes the commissioner of the department to reduce the royalty on a producing oil field if the reduction is necessary to "prolong the economic life of an oil and gas field." Thus, this provision is designed to accomplish for royalties what the ELF is designed to accomplish for severance taxes: to prevent the premature shutdown of a producing field by "reducing costs in the later stages of production decline." The statute specifies that "the commissioner may not grant a reduction of royalty until two years' initial production from the field

has occurred and each lessee requesting the reduction has made a clear showing" that continued production is *uneconomic*.

The section of the state oil and gas leasing law which authorizes the commissioner to unitize leases, AS 38.05.180(p), also authorizes the commissioner to "establish, *change* or revoke drilling, producing, and *royalty* requirements of the leases. . ." being unitized (emphasis added). Companies have applied to the department for a reduction of the royalty terms of their leases under this provision. The department has rejected such applications on the grounds that it may only entertain applications for royalty reduction under the terms of AS 38.05.180(j), because the latter is a specific statute governing royalty reduction and AS 38.05.180(p) is a general provision authorizing "change" in the context of unitization. According to the legal interpretation of the department, a specific statute takes precedence over a general one. Use of AS 38.05.180(p) to change royalty terms is an issue in the current effort of British Petroleum to unitize the area of the Badami discovery.

Alaska Statutes 38.05.140(d) authorizes the commissioner to reduce royalties on certain minerals. Until 1978, the list included oil and gas. However, oil and gas were removed from this provision in 1978 (Chapter 155 SLA 1978). According to Mr. Eason's letter, the department never received an application for royalty reduction on an oil and gas lease under the provision, but a number of active leases today contain language from the statute prior to its amendment in 1978.

Until 1969, state law granted a five-year royalty reduction from 12.5 percent to 5 percent for the holder of a lease "who shall drill and make the first discovery of oil or gas in commercial quantities in any geologic structure. . ." (AS 38.05.180[a]). This discovery royalty reduction was included in all leases, and it was nondiscretionary in the sense that it did not require a finding of the commissioner that approval was in the best interest of the state. However, it did require the commissioner to decide whether production was from a new geologic structure or the extension of a known structure, and on this basis several applications were denied. Although repealed in 1969 (Chapter 65 SLA 1969), this provision was included in all leases issued up to that time. According to Mr. Eason's letter, two producing leases on the North Slope are currently enjoying the benefits of the discovery royalty reduction. Also, some 340 active leases contain the provision, "an indeterminable number of which could potentially produce future discovery royalty applications."

Exploration Incentives

Alaska Statutes 38.05.180(i) authorizes the commissioner to establish an exploration incentive credit (EIC) system for exploratory wells and geophysical work. The law permits up to half of the cost of the exploratory work to be taken as a credit against royalties, rentals, or severance taxes

Representative Green
February 14, 1995
Page 7

due to the state. The department includes an EIC provision in leases that may need the additional enticement for companies to explore. Leases of attractive prospects do not carry an EIC provision. According to Mr. Eason's letter, there are currently 187 active leases with EIC provisions; 20 applications for EICs have been granted, and 1 denied. Apparently no lease sale since 1991 has included EIC provisions. The value of credits taken to date is about \$58.7 million.

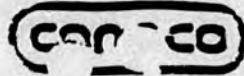
Last session, the legislature adopted SB 151 (Chapter 39 SLA 1994) that created additional exploration incentives that are "distinct from the exploration incentive credit authorized by AS 38.05.180(i). . . ." The new law, AS 41.09.010 applies to exploratory drilling and geophysical work "regardless of whether the land is state-owned land." Up to 50 percent of the cost of qualifying activity on state land may be taken as a credit against oil and gas corporate income taxes and lease bonus payments; 25 percent of the cost of qualifying activity on private land may be taken as a credit. No single project may receive a credit in excess of \$5 million, and no more than \$30 million in credits may be claimed during the ten-year life of the program. A company taking a credit must share with the state the raw data obtained from the exploratory well or geophysical survey. Regulations to implement this program have not yet been adopted.

The foregoing royalty reductions and exploration credits are addressed in more detail in the letter and documentary material from Mr. Eason, which is attached. I hope this overview of oil and gas incentives is helpful. If you have any questions or would like additional information, please call.

Attachments

ATTACHMENTS

Letter and Documents from James E. Eason to Gordon S. Harrison, February 8, 1995



David L. Bowler
Division Manager

Conoco Inc.
Suite 200
3201 C Street
Anchorage, AK 99503

February 27, 1990

RECEIVED

FEB 28 1990

DIV. OF OIL & GAS
DIRECTOR'S OFFICE

Ms. Lennie Gorsuch, Commissioner
State of Alaska, Department of Natural Resources
P. O. Box M
Juneau, Alaska 99811

Dear Commissioner Gorsuch:

(RE: Application for Royalty Reduction, Milne Point Unit, Conoco Working Interest in the Kuparuk River Participating Area

Attached is Conoco's application for a royalty reduction under the provisions of Section 18(h)(8) of the Milne Point Unit Agreement, and, alternatively, under the provisions of AS 38.05.180(j) and AS 38.05.180(p). This application requests an effective date of February 1, 1990, and requests a royalty reduction to 5% on all future Kuparuk River Formation production from ADL Leases No. 47433, 47434, 47437, 47438, and 28231.

Conoco also requests that all royalty payments after February 1 in excess of 5% be paid to a suspense account until final disposition of this application. Placing these royalties in a suspense account will facilitate final royalty adjustments after a decision has been reached by your Department, and may also lessen the time pressures that may be involved in reaching this decision. If DNR is willing to pursue this alternative, please have the appropriate DNR or Department of Revenue personnel contact me at their earliest convenience. The arrangements to establish this suspense account need to be finalized prior to the end of March.

Pursuant to 11 AAC 83.185(a)(5), Conoco hereby agrees to defray the cost of publishing any public notice required under 11 AAC 83.185(b).

This application contains cost and financial information that is confidential. Under the provisions of 11 AAC 82.810, Conoco requests that this entire application be held confidential. Conoco will submit a publicly available version of this application within 10 days of this filing. If this procedure is unacceptable to you, please provide us with 10 days notice before any proposed or possible release of any material so that we can take the necessary steps to protect our confidential interests.

Conoco believes that this application is complete and satisfies all of the application requirements contained in the Unit Agreement as well as all statutory and regulatory requirements. However, if you or your staff needs additional data, please contact Al Hastings at 564-7650.

Enclosure 1

000091

Ms. Lennie Gorsuch, Commissioner
February 27, 1990
Page 2

Thank you for your consideration of this application. This issue has been simmering for nearly seven years, and now is an appropriate time to reach a mutually satisfactory solution.

Very truly yours,


David L. Bowler
Division Manager

AEH(jr)
Attachment
(File

000092

CONOCO

David L. Bowler
Division Manager

Conoco Inc.
Suite 200
3201 C Street
Anchorage, AK 99503

Public

February 28, 1990

RECEIVED

FEB 28 1990

DIV OF OIL & GAS
DIRECTOR'S OFFICE

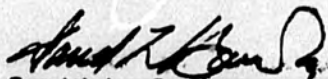
Ms. Lennie Gorsuch, Commissioner
State of Alaska, Department of Natural Resources
P. O. Box M
Juneau, AK 99811

Dear Commissioner Gorsuch:

Attached is the Public Version of the Royalty Reduction Application for the Milne Point Unit filed with your Department of February 28, 1990. Also attached is an errata page correcting a date in the previous application. The date in the Public Version has been corrected.

If I can be of further assistance, please give me a call at 564-7601.

Very truly yours,



David L. Bowler
Division Manager

AEH(jr)
Attachments
File 500.58.10

1
2 PUBLIC VERSION

3
4 BEFORE THE ALASKA DEPARTMENT OF NATURAL RESOURCES

5 In the Matter of:)
6 A Request by Conoco for)
7 Royalty Reduction on ADL)
8 47433, 47434, 47437, 47438)
9 and 28231 (Kuparuk)
10 Participating Area: Milne)
11 Point Unit).)
12

13
14 I. INTRODUCTION

15 Conoco owns a 72.149% interest in the Kuparuk Participating
16 Area of the Milne Point Unit. Four of Conoco's leases within the
17 participating area were acquired in 1969. The remaining lease,
18 ADL 28231, was originally issued in 1965, and acquired by Conoco
19 from Atlantic Richfield Company in 1988. All five leases were
20 executed on form ADL-1, and each provided a standard 12.5% royalty.

21 However, when Conoco and other companies participating in
22 Milne Point development petitioned the state for approval of the
23 Milne Point Unit in 1979, the Alaska Department of Natural
24 Resources ("DNR") refused to approve the unit unless the companies
25 agreed to a special royalty surcharge. As a result, the September
26 28, 1979 Milne Point Unit agreement, as drafted by DNR, requires
Conoco to pay a 20% royalty on the four 1969 leases. Attachment

These leases are referred to as the "1969 leases," and
include ADL 47433, 47434, 47437 and 47438.

BRUCE L. HORTON, DEPUTY ATTORNEY GENERAL
STATE OF ALASKA
10075 10th Ave
JAN 21 1986
JAN 21 1986
JAN 21 1986

1 A, ¶14. Conoco continues to pay a 12.5% royalty on ADL 28231.

2 DNR informed Conoco, at the time, that the royalty surcharge
3 was being imposed in response to substantial oil price increases
4 that had occurred since 1969 -- increases that DNR believed would
5 allow a greater state share of Milne Point revenues without
6 impairing field profitability. According to DNR:

7 ...the economics of oil and gas leasing have
8 changed so drastically within the past ten
9 years that in order to effectively protect the
10 state's interests, certain changes in the
11 lease are necessary.

12 The royalty surcharge was an experimental policy that was
13 short lived. For example, when the proposed Kuparuk River Unit
14 came before the Department two years later, DNR approved it without
15 any required royalty increase.

16 The history of Milne Point's development and production is set
17 out in Exhibit A to the Affidavit of Alan Hastings. The working
18 interest owners in the Kuparuk Participating Area committed to
19 initial Kuparuk River Formation development in January, 1984. At
20 that time, ANS wellhead prices were about \$20/bbl., and were
21 expected to increase. Id. By the time production commenced in
22 November, 1985, however, ANS wellhead prices had dropped to

23
24
25
26 LeResche to High letter, September 19, 1979 at 1.
Attachment B.

1 \$14/bbl.' In comparison, the state believed at the time the
2 surcharge was imposed in 1979 that by 1985 ANS wellhead prices
3 would have reached \$34/bbl.'

4 Because of the decline in ANS prices, and Milne Point's
5 marginal production rates,' Milne Point owners could not hope to
6 recover their capital investment from projected unit production,
7 at least as long as the surcharge remained. Accordingly, on
8 November 1, 1985, Conoco and other Milne Point working interest
9 owners' requested DNR to reconsider its 1979 unit decision, and to
10 change the royalty requirements of the unit agreement under AS
11 38.05.180(p). The request, at the time, was limited to removal of
12 the 7.5% royalty surcharge. The companies' supporting papers
13 showed that, under the Department of Revenue's then-existing price
14 forecasts, and with the royalty surcharge, production from the
15 Kuparuk Participating Area would return only [] annually on the
16
17
18

19 ' Petroleum Production Revenue Forecast, Alaska Department of
20 Revenue, June 1985 at 11.

21 ' Petroleum Production Revenue Forecast, Alaska Department of
22 Revenue, December 1979 at 5.

23 ' During 1986, for example, production ranged from 10,000 to
24 15,000/bbl./day from the participating area, with peak production
forecasts ranging from 25,000 to 30,000/bbl./day.

25 ' These included Reading and Bates Petroleum Co., Champlin
26 Petroleum Co., and Cities Service Oil and Gas Corporation.

JOHN, BITTNER AND CHEROT
ATTORNEYS AT LAW
ONE MI ALASKA PLAZA, SUITE 101
JL NEAR ALASKA 99501
(907) 566-2800

MICHAEL J. BROWN, DEPUTY SECRETARY
ALASKA DEPARTMENT OF NATURAL RESOURCES
1000 EAST 10TH AVENUE, SUITE 100
ANCHORAGE, ALASKA 99501
(907) 266-2000

1 company's capital investment.' Given Conoco's then-existing 15%
2 cost of capital,' projected Kuparuk Participating Area return would
3 be insufficient to allow the companies to ever recoup their capital
4 investment, much less earn any profit.

5 DNR never took final agency action on Conoco's 1985 request.
6 Rather, on February 5, 1986, DNR Commissioner Esther Wunnicke
7 proposed that the parties negotiate a royalty realignment, and
8 advised that:

9 I anticipate that staff would not be able to
10 continue evaluating your original [November 1,
11 1985] applications while actively negotiating
12 the remaining issues associated with our
13 proposed royalty alteration.'

14 Negotiations were unsuccessful, and DNR took no further action
15 on the 1985 application.

16 In the meantime, ANS wellhead prices plummeted. From the 1985
17 price of \$14/bbl. that provoked the company's 1985 request, Milne
18 Point's average wellhead price declined in 1986 to \$3.83/bbl."
19 These prices made continued production at Milne Point impossible;
20 and, in December, 1986, DNR granted Conoco permission to suspend

21 ' In the Matter of a Request by Conoco, et al, November 1,
22 1985 (hereinafter "1985 Request"), Affidavit of David Uldrich at
23 4.

24 ' Id.; Affidavit of Lou L. Pai at 1.

25 ' Wunnicke to Kemp letter, February 5, 1986 at 3 (Attachment
26 C hereto).

27 ' Hastings Aff. at Ex. I - J.

ALBION, ILLINOIS AND CHEROKEE
STATIONERS
ONE STATE STREET, ALBION, ILL. 61710
TEL: 815/461-1000
FAX: 815/461-1001

1 operations on the unit." Production was actually suspended in
2 January, 1987. Id.

3 Production from the Kuparuk Participating Area resumed in
4 April, 1989, with daily production reaching 20,000 barrels by the
5 end of the year. Id. During that year, Milne Point wellhead
6 prices averaged \$9/bbl. -- \$5/bbl. less than when the company
7 submitted its Request in November, 1985."

8 This current Request for royalty relief is occasioned by the
9 fact that Milne Point production has crossed a threshold of sorts.
10 As of February 1, 1990, there have been two years production from
11 the field. Hastings Aff. at ¶5. During the suspension period,
12 DNR discouraged Conoco from pursuing royalty relief because both
13 §18(h)(8) of the Milne Point Unit agreement, and AS 38.05.180(j),
14 required two years' production as a precondition of royalty
15 relief." DNR has ruled that two years' production need not be
16 continuous; rather, according to DNR Commissioner Judith Brady, the
17 production history requirement "is tolled during the period
18 production is suspended." Excluding the tolled period of
19

20 " Id. at Ex. A.

21 " Hastings Aff. at Ex. I - J.

22 " The two year production requirement, however, does not
23 apply to a request to change royalty requirements under AS
24 30.05.180(p).

25 " Brady to Painter letter, April 29, 1987 at 1 (Attachment
26 D.)

MICHEL HORTON, BITTNER AND CHEROT
ATTORNEYS AT LAW
ONE SEALASKA PLAZA, SUITE 101
JUNEAU, ALASKA 99901
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1 suspension, production between November, 1985 and the present now
2 exceeds two years.

3 The change in royalty is sought under §18(h)(8) of the Milne
4 Point Unit agreement, which provides:

5 After two years initial production from the
6 field in which the leased area is located has
7 occurred, the State may reduce lessees
8 obligations to pay royalty on all of the
9 leased area or on any tract or portion thereof
10 segregated for royalty purposes upon (1)
11 request by a lessee and (2) a clear showing by
12 lessee that the revenue from all oil, gas and
13 associated substances produced from the field
14 is insufficient to produce a reasonable rate
15 of return with respect to lessee's total
16 investment in the field.

17 See Attachment A at 23-24.

18 As authorized by §18(h)(8), this request seeks a royalty
19 change only for that "portion" of the unit comprising the Kuparuk
20 Participating Area -- an area that will be segregated for royalty
21 purposes. Hastings Aff., ¶3. Conoco is requesting an amendment
22 to the royalty requirements of the unit agreement, and the
23 underlying leases, providing for a royalty of 5%. As the company's
24 supporting papers show, based on the Department of Revenue's
25 current mid-scenario crude oil price projections, a 20% royalty
26 will provide a rate of return of only [], far below the
company's cost of capital. At a 5% royalty rate, the crude oil
price must exceed the Department of Revenue's high scenario price
forecast by 20% for Conoco to just recover its cost of capital.
Thus, a royalty of no more than 5% is necessary to afford the
company any realistic opportunity to recover its capital costs.

CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION



Rev. 6/98

Central Microfilm Services
Department of Education
State of Alaska

1 operations on the unit." Production was actually suspended in
2 January, 1987. Id.

3 Production from the Kuparuk Participating Area resumed in
4 April, 1989, with daily production reaching 20,000 barrels by the
5 end of the year. Id. During that year, Milne Point wellhead
6 prices averaged \$9/bbl. -- \$5/bbl. less than when the company
7 submitted its Request in November, 1985.¹²

8 This current Request for royalty relief is occasioned by the
9 fact that Milne Point production has crossed a threshold of sorts.
10 As of February 1, 1990, there have been two years production from
11 the field. Hastings Aff. at ¶5. During the suspension period,
12 DNR discouraged Conoco from pursuing royalty relief because both
13 §18(h)(8) of the Milne Point Unit agreement, and AS 38.05.130(j),
14 required two years' production as a precondition of royalty
15 relief.¹³ DNR has ruled that two years' production need not be
16 continuous; rather, according to DNR Commissioner Judith Brady, the
17 production history requirement "is tolled during the period
18 production is suspended."¹⁴ Excluding the tolled period of
19

20 " Id. at Ex. A.

21
22 " Hastings Aff. at Ex. I - J.

23 " The two year production requirement, however, does not
24 apply to a request to change royalty requirements under AS
30.05.130(p).

25
26 " Brady to Painter letter, April 29, 1987 at 1 (Attachment
D.)

BIRCH, HORTON, BITTNER AND CHIEROT
ATTORNEYS AT LAW
ONE SIX ALASKA PLAZA, SUITE 101
JUNEAU, ALASKA 99801
(907) 586-2800

1 suspension, production between November, 1985 and the present now
2 exceeds two years.

3 The change in royalty is sought under §18(h)(8) of the Milne
4 Point Unit agreement, which provides:

5 After two years initial production from the
6 field in which the leased area is located has
7 occurred, the State may reduce lessees
8 obligations to pay royalty on all of the
9 leased area or on any tract or portion thereof
10 segregated for royalty purposes upon (1)
11 request by a lessee and (2) a clear showing by
12 lessee that the revenue from all oil, gas and
13 associated substances produced from the field
14 is insufficient to produce a reasonable rate
15 of return with respect to lessee's total
16 investment in the field.

17 See Attachment A at 23-24.

18 As authorized by §18(h)(8), this request seeks a royalty
19 change only for that "portion" of the unit comprising the Kuparuk
20 Participating Area -- an area that will be segregated for royalty
21 purposes. Hastings Aff., ¶3. Conoco is requesting an amendment
22 to the royalty requirements of the unit agreement, and the
23 underlying leases, providing for a royalty of 5%. As the company's
24 supporting papers show, based on the Department of Revenue's
25 current mid-scenario crude oil price projections, a 20% royalty
26 will provide a rate of return of only [], far below the
company's cost of capital. At a 5% royalty rate, the crude oil
price must exceed the Department of Revenue's high scenario price
forecast by 20% for Conoco to just recover its cost of capital.
Thus, a royalty of no more than 5% is necessary to afford the
company any realistic opportunity to recover its capital costs.

1 The request also asks that the royalty change be effective as
2 of February 1, 1990 -- that date on which two years' initial
3 production was achieved. The purpose of §18(h)(8) -- to allow the
4 survival of marginal fields after two years' production experience
5 (see infra) -- would be best served by applying the relief at the
6 earliest possible date.

7 Conoco believes that §18(h)(8) is the most appropriate vehicle
8 for conforming Milne Point's royalty requirements to economic
9 reality. Section 18(h)(8) is a unique royalty reduction
10 requirement, inserted in the agreement to mitigate the impact of
11 the agreement's special royalty surcharge. It is worded
12 differently than the more general royalty reduction provision of
13 AS 38.05.180(j), and, as the Attorney General has already decided,
14 because §180(j) post-dated execution of Conoco's leases, it is the
15 unit agreement, rather than §180(j) itself, that establishes the
16 requirements for reduced royalties."

17 The special language of §18(h)(8) is absent from the unit
18 agreements governing other active units in the state. For example,
19 the Kuparuk River Unit agreement, lacking any special royalty
20 surcharge, likewise lacks any special provision for royalty
21 reduction. Thus, §18(h)(8) affords DNR the opportunity to tailor
22 royalty requirements to the economic conditions of Milne Point,
23 without affecting DNR's relationship with other lessees, or other
24 units.

25 _____
26 This to Brown Memorandum, "Conoco Milne Point Royalty
Reduction Request," April 24, 1984 at 5. Attachment E.

1 Alternatively, should the agency find that AS 38.05.130(j),
2 rather than §18(h)(8) of the unit agreement, governs this request,
3 Conoco has also met the requirements for a royalty change under
4 that subsection.

5 Finally, independent of both §18(h)(8) and §130(j), Conoco
6 remains entitled to a royalty change under AS 38.05.130(p).
7 Because DNR has never taken final agency action on its 1985
8 request, the company's entitlement to relief under that subsection,
9 and its request for reconsideration of DNR's 1979 surcharge
10 decision, remain before the Department. With respect to the 1985
11 Request, this request therefore:

12 1. modifies the 1985 Request by requesting a 5% royalty for
13 the Kuparuk Participating Area leases referenced above, rather than
14 removal of the royalty surcharge for the unit as a whole; and

15 2. updates the economic information in the 1985 Request based
16 upon new Department of Revenue oil forecasts, actual production
17 history, and other new economic information contained in this
18 request."

19
20
21
22 _____
23 " Should DNR decide that, by inaction or otherwise, it has
24 taken "final agency action" on the 1985 request, this request
25 should be considered as a new request for relief under §130(p).
26 Circumstances between 1985 and 1990 have changed. Because this
 request is based on facts different than those underlying the 1985
 request, even "final agency action" on the 1985 request would not
 limit Conoco's ability to pursue relief at this point. K. Davis,
 Administrative Law, 3rd Ed., §18.04.

ERIC H. HORTON, BILL ENTERSUCHEROT
ALASKA DEPARTMENT OF REVENUE
1000 EAST 10TH AVENUE, SUITE 100
ANCHORAGE, ALASKA 99501
907-269-2600

1 II. THE ECONOMIC JUSTIFICATION FOR A ROYALTY REDUCTION

2
3 Under §18(h)(8) of the Milne Point Unit agreement, a royalty
4 reduction is warranted upon a:

5 ...showing by lessee that the revenue from all
6 oil, gas and associated substances produced
7 from the field is insufficient to produce a
8 reasonable rate of return with respect to
9 lessee's total investment in the field.

10 Conoco has already made that showing, to DNR's satisfaction,
11 through its 1985 request; its request for suspension of production;
12 and its periodic royalty reports filed with the agency. With that
13 information before it, DNR was able to conclude on April 29, 1987
14 that:

15 Staff from the Division of Oil and Gas concur
16 with Conoco's economic assessment of the
17 losses incurred by continued production at
18 Milne Point, and agree that had those losses
19 been experienced over a two year production
20 history, a royalty reduction would be
21 advisable."

22 The supporting papers to this request both: (1) confirm those
23 losses, and Conoco's insufficient return, over two years of
24 production; and (2) show that, based upon the state's own price
25 projections, and with the royalty surcharge, the company will never
26 receive an adequate rate of return from Kuparuk Participating Area
27 production. 11 AAC 83.135 sets out the information needed for a
28 royalty reduction request, and by its terms seeks only historical

29
30 " Brady to Painter letter, supra note 14 at 1.

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JUNEAU, ALASKA 99801
(907) 586-2000

1 data." The specific information required by §185(a)(2) - (4) is
2 provided, respectively, in Exhibits A and E - G of Mr. Hastings'
3 affidavit.

4 This request, however, goes further, and also provides
5 projected returns under varying royalty scenarios. See Hastings
6 Aff. at ¶11-12. Together, this data demonstrates that:

7 1. In November, 1985, the company's cost of capital was 15%.
8 Pai Aff. at p. 1. The company's current cost of capital is 12%.
9 Hastings Aff., ¶13. Thus, annual net income, net of royalties,
10 must be sufficient to allow the company to recover its capital,
11 plus allow a 12% rate of return in order for the company to break
12 even. Pai Aff. at Attachment B; Hastings Aff. at ¶¶13-14. Income
13 greater than that amount would result in profit. Income less than
14 that would represent a loss. Id.

15 Exhibit E to the Hastings Affidavit shows that Conoco's total
16 capital investment in the Kuparuk Participating Area has been
17 \$222.9 million. Exhibit F reports Conoco's operating income for
18 1986 and 1989, respectively, at \$8.76 million and \$19.37 million.
19 Operating income during those years, then, was [] and [],
20
21
22
23
24

25 " For example, the regulation asks for a description of "all
26 past and present activities"; seeks production data "during the six
months preceding...the application"; and cost and income data for
"the entire life of the lease."

1 respectively, of total capital investment." As a result, during
2 the two years of production, Conoco has been unable to meet the 12%
3 rate of return threshold, even if no operating income were assigned
4 to capital recovery. It was as though a bank, needing 12% interest
5 on a loan to cover its cost of borrowing, received only []
6 interest and no payment on the principal.

7 This historical data is a reliable indicator of future losses.
8 Granted, production to date has not exceeded 20,000/bbl./day,
9 while Conoco projects that 1990 production may approach
10 24,000/bbl./day. Hastings Aff., Ex. I - J. On the other hand,
11 additional capital expenditures will be made in 1990 in order to
12 achieve that increased production. Two additional wells have
13 already been drilled for the participating area, and two more are
14 scheduled during this calendar year. Id. at Ex. A. As a result,
15 from historical data alone, DNR may comfortably conclude that
16 revenues from the participating area will be insufficient to allow
17 Conoco to recover its capital, much less realize "a reasonable rate
18 of return with respect to lessee's total investment in the field."

19 2. The Hastings Affidavit also appends projections of future
20 costs, revenues and rates of return. Id. at Ex. I - J. These

21
22 " These percentages overstate the relationship of operating
23 income to capital costs since, for example, 1989 income is
24 expressed in 1989 dollars, while capital costs are expressed in
25 nominal dollars for the year in which they were incurred. That
26 overstatement is partially offset by the fact that 1989 operating
income reflects only 9 months of production. On balance, however,
the nominal relationship between the figures is sufficient to show
that revenues have been substantially less than those necessary to
ever recover the company's capital investment and cost of capital.

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1 attachments employ the same methodology used by Conoco in 1985 to
2 project future revenues. See 1985 Request, Uldrich Affidavit. The
3 revised projections reflect, among other intervening changes:

- 4 a. lower Department of Revenue price forecasts;
5 b. differing operating and capital costs, based on two years'
6 actual experience; and
7 c. the loss in the real value of production income because
8 production was delayed because of the suspension. Hastings Aff.,
9 at ¶10.

10 Those projections show that, with a 20% royalty, total cash
11 flow revenues will average only [] of total capital investment.
12 To break even -- that is, to yield revenues equal to the amount
13 necessary to recover Conoco's capital and yield a 12% rate of
14 return -- requires both a royalty of 5% and a crude price
15 significantly above current mid-scenario projections. That is the
16 royalty sought by this request. While DNR cannot control oil
17 prices, it can control the other variable affecting capital
18 recovery -- the royalty. Without a reduction in the royalty to 5%,
19 the company has no realistic chance at recovering its capital, even
20 with significantly higher oil prices.

21
22 III. ROYALTY RELIEF SHOULD BE GRANTED UNDER §18(h)(8)
23 OF THE MILNE POINT UNIT AGREEMENT
24

25 Conoco's ADL-1 leases allowed a royalty reduction whenever the
26 Commissioner found it "necessary for the purpose of encouraging

MR. G. BROWN: REINTER-CONCERN
QUESTIONS OF
GENERAL COUNCIL, 1984
REINTER-ALASKA
1984-1985

1 the greatest ultimate recovery of oil and gas." In 1978, the
2 legislature tightened the conditions under which royalties could
3 be reduced on future oil and gas leases. Ch. 155, SLA 1978; AS
4 38.05.180(j). However, the company's leases incorporated Alaska
5 statutes only as they existed at the time of lease issuance (see
6 ADL-1, ¶42), and Ch. 155, SLA 1978 operated prospectively only.
7 State of Alaska v. Pulp America, Inc., 674 P.2d 268, 272 (Alaska
8 1983).

9 Both DNR and the Attorney General have concluded that the 1978
10 legislative changes did not, in and of themselves, amend the
11 royalty reduction provision of Conoco's leases.¹⁰ Rather, and as
12 these agencies have acknowledged, Conoco's contractual right to a
13 royalty reduction under its leases would be altered only by a
14 subsequent contract between DNR and the company -- in this case,
15 the Milne Point Unit agreement. Id.

16 The unit agreement does alter Conoco's right under its leases
17 to a reduction of the lease royalty." It did so, however, not by
18 following the language of §180(j), but rather by creating a special
19 royalty reduction provision in §18(h)(8).

20 The reason for this special royalty reduction provision is
21 apparent. The royalty surcharge in the unit agreement was imposed

23 ¹⁰ Brown to Haley letter, October 9, 1984 at 2 (Attachment F);
24 Thie to Brown letter, note 15, supra at 4 - 5.

25 ¹¹ It does not, however, purport to alter the Commissioner's
26 authority under AS 38.05.130(p) -- a separate issue that is
addressed in the company's 1985 Request.

MILNE POINT UNIT AGREEMENT
DNR ALASKA
1979

1 because of DNR's expectation of high oil prices, and substantial
2 industry profits." The surcharge was the result of a new and
3 experimental policy. To guard against the possibility that DNR's
4 price assumptions were wrong, or that the experiment would impair
5 field development, DNR also needed to preserve flexibility in
6 adjusting future royalties as an integral part of its new policy.

7 The special royalty surcharge, and special royalty reduction
8 provisions, thus went hand-in-hand -- a fact apparent from the
9 history of the unit agreement. As originally drafted, the
10 agreement contained neither a royalty surcharge nor any special
11 royalty reduction provision. See Attachment G. Rather, §18(h) (8)
12 first appeared in the September, 1979 draft that also first
13 proposed the royalty surcharge -- a draft prepared by DNR and
14 presented to the companies on a take-it-or-leave-it basis."
15 Section 18(h) (8) was thus as consciously tailored to Milne Point
16 as the royalty surcharge itself.

17 The parties' intent to treat royalties, and royalty
18 reductions, differently for Milne Point than for other units is
19 also apparent by comparing the Milne Point Unit agreement with the
20 agreements governing other active units in the state. After Milne
21 Point, the next major unit approved by DNR was the Kuparuk River

22 _____
23 " See page 2, supra.

24 " Compare LeResche to High letter, note 2, supra, and
25 LeResche to High letter, October 23, 1979 (Attachment H) (DNR
26 "intends to approve" the unit agreement precisely as presented by
DNR in the September 19, 1979 draft containing the royalty
surcharge/royalty reduction language.)

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NATURAL RESOURCES
JAN 14 1982

1 Unit in December, 1981. By then, the State had abandoned its
2 policy of demanding royalty surcharges as a condition of unit
3 approval. The Kuparuk River Unit agreement thus contains no
4 royalty surcharge, and neither does it include any special
5 treatment of royalty reductions. Rather, the Kuparuk agreement
6 implicitly leaves royalty reductions to current general law,
7 including §180(j), by incorporating all applicable laws "in effect
8 on the effective date [of the unit agreement]" into the unit
9 agreement itself. Id., section 17.1.

10 The Milne Point Unit agreement also contains a general clause
11 incorporating then-applicable law. That boilerplate proviso,
12 however, does not affect the special treatment given royalty
13 reductions in §18(h)(8). First, section 1 of the Milne Point Unit
14 agreement incorporates then-existing law only to the extent that
15 it is "not inconsistent with the terms [of the unit agreement]" -
16 - a limitation conspicuously missing from section 17 the Kuparuk
17 River Unit agreement.

18 Second, there would have been no need for DNR to propose
19 special royalty reduction language in §18(h)(8) if the agency
20 intended to simply leave the royalty reduction question to §180(j)
21 pursuant to §1 of the unit agreement. It is common, of course, for
22 government contracts to broadly incorporate entire government
23 codes, but then specifically deal with a particular topic that is
24 also covered by those generally incorporated laws. In that case,
25
26

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1 the contract's specific treatment of the subject will prevail."
2 The reasons are obvious:

3 (1) where a contract specifically deals with the parties'
4 rights or obligations (as §18(h)(8) does here with respect to
5 royalty reductions), the parties are entitled to presume that the
6 language of the specific section was purposeful and complete;

7 (2) thus, imposing different or supplemental conditions on
8 exercising that right through a general incorporation clause would
9 be inconsistent with the specific section;

10 (3) in most cases, and certainly here, there is no indication
11 that the parties considered the specific subject matter (here
12 royalty reductions) when reviewing the general incorporation
13 clause; and

14 (4) the incorporation clause is a mere form provision, which
15 provides a particularly weak basis for modifying the terms of the
16 specific provision. Id.; Craig Taylor Equipment Co. v. Pettibone
17 Corporation, 659 P.2d 594 (Alaska 1983) (form contracts are
18 construed against the party providing the form).

19 Since, as the parties agree, only the unit agreement could
20 change Conoco's contractual entitlement to royalty relief in the
21 original lease, and since §18(h)(8) of the unit agreement treats
22 the issue of royalty relief in a specific and comprehensive way,
23 that section governs Conoco's entitlement to relief in the present
24 case.

25 _____
26 " McBride, Government Contracts, Matthew Bender, 1989,
section 2.150 at 2-305.

1 IV. IN THE ALTERNATIVE, CONOCO IS ENTITLED TO RELIEF
2 UNDER AS 38.05.180(j)
3

4 AS 38.05.180(j) comprises two sentences. The second sentence
5 is essentially identical to §18(h)(8) of the unit agreement, and
6 provides:

7 The Commissioner may not grant a reduction of
8 royalty until two years initial production
9 from the field has occurred and each lessee
10 requesting the reduction has made a clear
11 showing that the revenue from all hydrocarbons
produced from the field is insufficient to
produce a reasonable rate of return with
respect to that lessee's total investment in
the field.

12 As it has under §18(h)(8), Conoco has made this showing for
13 the purposes of §180(j).

14 While this second sentence limits the Commissioner's authority
15 to grant any royalty reduction, the first sentence of §180(j) deals
16 with a different issue -- the imposition of a mandatory obligation
17 on the Commissioner to write regulations authorizing royalty
18 reductions in particular cases:

19 To prolong the economic life of an oil and gas
20 field, the Commissioner shall adopt
21 regulations for all bidding methods to allow
22 reduction of royalty on leases within the
field to compensate for increasing costs in
the later stages of production decline.

23 Emphasis added.

24 Even if this first sentence also served as a limitation on
25 DNR's authority to grant any royalty reduction -- that is, if a
26 royalty reduction were allowable only "to prolong the economic life

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1 of an oil field," and then only if the reduction was needed "to
2 compensate for increasing costs in the later stages of production
3 decline" -- Conoco would meet those standards. First, there is no
4 question that granting the relief sought by this request would
5 prolong Milne Point's economic life. The nearly two year shut-in
6 period is evidence enough of Milne Point's peculiar economic
7 susceptibility; and, the conclusion is inescapable that if the
8 companies continue to suffer the substantial losses demonstrated
9 by this request's supporting papers, the economic life of Milne
10 Point would be materially reduced.

11 Milne Point is also in the "later stages of production
12 decline." Conoco is already engaged in secondary recovery.
13 According to then DNR Deputy Commissioner Jack Roderick, the
14 purpose of the first sentence of §180(j) was "to save the field,"
15 and avoid "possible premature abandonment." Minutes, House
16 Resources Committee, March 16, 1978 at 3. Under the first sentence
17 of §180(j), then, the legislature sought to encourage producers to
18 invest in secondary and tertiary recovery by ensuring that royalty
19 rates could be reduced in order to compensate for those increased
20 costs.

21 The purpose of §180(j)'s first sentence neatly fits Milne
22 Point. As the Hastings' Affidavit explains, Milne Point has been
23 engaged in costly secondary recovery, through water flooding, since
24 the onset of production. Id. at ¶4. Secondary recovery has been
25 used from the outset of production in order to avoid an immediate
26 and substantial drop in reservoir pressure that would have impaired

1 future production from the field. Because of low initial reservoir
2 pressures in the Kuparuk River formation, conventional primary
3 production could have resulted in gas saturation of the formation's
4 oil reserves, making subsequent water flooding far less effective,
5 and significantly reducing ultimate total recovery. Id. Had
6 secondary recovery not commenced from the outset, the useful life
7 of the reservoir would have been reduced, and commercial
8 development of the field would have been questionable. Id. As a
9 result, Milne Point presents precisely that kind of situation which
10 the legislature intended to address in §180(j)'s first sentence.

11 However, it is doubtful that the legislature ever intended
12 that the first sentence of §180(j) would modify the second. The
13 two sentences, after all, address different purposes -- the first
14 requiring DNR to draft regulations for royalty reductions to
15 compensate for secondary and tertiary recovery, while the second
16 defines the Commissioner's authority to grant royalty reductions
17 generally. In describing the purpose of §180(j) to the House
18 Resources Committee, the Legislative Affairs Agency described the
19 new royalty reduction provision as "retaining" the Commissioner's
20 authority "to reduce the royalty rate on tracts having marginal
21 production."³ Section 180(j) is consistent with that broad
22 characterization only if the second sentence stands on its own.

23
24 ³ Erickson to Osterback memo, March 15, 1978 at 1.
25 Characterization was made with reference to the original version
26 of HB 854, which, as to the first sentence of §180(j), was
identical to the version ultimately enacted. See HB 554, p. 3, ls.
4 - 7.

BIRCH HORTON, BITNER SOCIETY
QUESTIONS
ONE STATE OF ALASKA, DECEMBER 1979
IF STATE OF ALASKA, 1979
1979, Vol. 2, p. 103

1 Additionally, if the first sentence implicitly limits the
2 second, then the two-year production requirement of the second
3 sentence becomes superfluous." The purpose of the two year
4 production limitation in §180(j) was to prevent a person from
5 offering a high royalty or net profit share bid, and then
6 immediately seeking to reduce that royalty after the lease sale."
7 The second sentence of §180(j) assures that the lessee will have
8 at least two years of production before seeking to change his bid
9 royalty. Yet if the first sentence of §180(j) already limited any
10 royalty reduction to the "later stages of production decline," then
11 there was no need to specify a particular production period in the
12 second sentence." The only way of accommodating the two year
13 production limitation of the second sentence and the "later stages
14 of production decline" limitation of the first sentence, such that
15 each serves a different purpose," is to conclude that the two
16 sentences address different matters.

17
18 " And, of course, every portion of a statute is presumed to
19 serve an independent purpose. Isakson v. Rickey, 550 P.2d 359, 364
20 (Alaska 1976).

21 " Testimony of DNR Commissioner Jack Roderick, House
22 Resources Committee, March 2, 1979, tape 71 at 1024; Testimony of
23 Milton Lipton, House Resources Committee, tape 71 at 1687.

24 " In some cases, such as Milne Point, production decline
25 requiring artificial recovery techniques may occur from the onset.
26 However, even in those cases, production would have to commence
before the first sentence would allow for a royalty reduction.

26 " Isakson v. Rickey, 550 P.2d at 364.

1 In summary, Conoco need not meet the first sentence of §180(j)
2 in order to obtain royalty relief under that statute; yet, even if
3 it must, the secondary recovery investments that the company has
4 made in order to combat what would otherwise be a rapid decline in
5 natural reservoir pressure places Milne Point both within the
6 language and purpose of the entire section.
7

8 V. CONOCO REMAINS ENTITLED TO RELIEF UNDER AS 38.05.180(p)

9 DNR's legal authority to change Conoco's royalty requirements
10 under AS 38.05.180(p) are set out in the company's 1985 Request,
11 which are incorporated in this request by reference and need not
12 be repeated here. The economic justification for granting that
13 relief is set out in part II of this request, and the request's
14 supporting papers. Conoco requests that DNR either: (1) grant the
15 company's 1985 Request, as modified by this request to require a
16 5% royalty for the above referenced leases in the Kuparuk
17 Participating Area; or (2) treat this request as a separate
18 submittal under §180(p), or the commissioner's reconsideration
19 authority, and grant the requested relief.
20

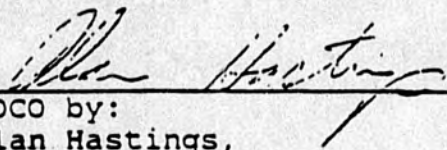
21 VI. CONCLUSION

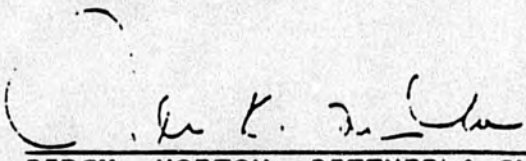
22 For the foregoing reasons, Conoco respectfully requests that:

- 23 1. the royalty on the above-referenced leases for the Kuparuk
24 Participating Area be reduced to 5%; and
25 2. the royalty change be made effective as of February 1,
26 1990.

ALASKA DEPARTMENT OF REVENUE
DIVISION OF OIL AND GAS
1110 NORTH Seward Street
Juneau, Alaska 99801
(907) 586-2200

1 DATED this 28th day of February, 1990.

2
3
4 
5 CONOCO by:
6 Alan Hastings,
7 Director of External Affairs

8 
9 BIRCH, HORTON, BITTNER & CHEROT by:
10 Jonathan K. Tillinghast,
11 Attorney for Conoco
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ATTACHMENT A TO CONOCO BRIEF

MILNE POINT UNIT AGREEMENT

DATED 9/28/79

ENCLOSURE 2

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June 1, 1990

DEPARTMENT OF
NATURAL RESOURCES

JUN 4 1990

COMMISSIONER'S OFFICE
JUNEAU

Commissioner Lennie Gorsuch
Department of Natural Resources
400 Willoughby Avenue
Juneau, Alaska 99811

Re: Application for Royalty Reduction, Milne Point Unit,
OXY USA Inc. Working Interest in the Kuparuk
Participating Area
Our File No.: 401553.1

Dear Commissioner Gorsuch:

Attached is OXY USA Inc.'s ("OXY") application for a royalty reduction under §18(h)(8) of the Milne Point Unit Agreement and, alternatively, AS 38.05.180(j) and AS 38.05.180(p). This application requests an effective date of February 1, 1990 for the royalty reduction, and requests a reduction to 5% on all Kuparuk River Formation production from ADL leases number 47433, 47434, 47437 and 47438. The application is supported by its own attachments, and also by the materials submitted by Conoco in November, 1985 and February 27, 1990. The Conoco materials are incorporated into this application by reference.

This application contains cost and financial information that is confidential. Both a confidential and publicly available version of the application are enclosed. Under the provisions of 11 AAC 82.810, OXY requests that the entire confidential application be held confidential under that regulation. If this procedure is unacceptable to you, please provide us with 10 days' notice before any proposed or possible release of any material so that we can take the necessary steps to protect our confidential interests.

OXY also requests that all royalty payments after February 1 in excess of 5% be paid into escrow until final disposition of this

Enclosure 2

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ANCHORAGE, ALASKA
JUN 15 1990

Commissioner Lennie Gorsuch
June 1, 1990
Page 2

application. Placing these royalties in a mutually agreeable escrow account will facilitate final royalty adjustments after a decision has been reached by your department, and may lessen the time pressures that may be involved in reaching this decision. If DNR is willing to pursue this alternative, please have the appropriate DNR or Department of Revenue personnel contact me at their earliest convenience.

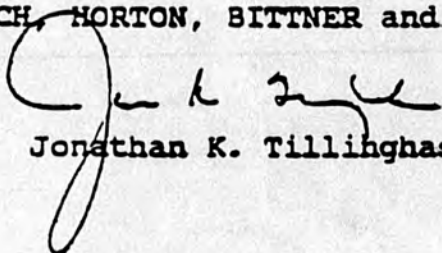
Pursuant to 11 AAC 83.180(a)(5), OXY hereby agrees to defray the cost of publishing any public notice required under 11 AAC 83.185(b). OXY also agrees to reimburse the reasonable transportation costs, and subsistence costs at normal state per diem rates, of a state auditor to conduct an audit at OXY's Tulsa, Oklahoma offices, of any information contained in this application.

OXY believes that this application is complete and satisfies all of the applicable requirements contained in the unit agreement, and pertinent statutes and regulations. However, if you or your staff need additional data please contact me.

Thank you for your consideration of this application.

Sincerely,

BIRCH, HORTON, BITTNER and CHEROT



Jonathan K. Tillinghast

JKT/amw

001281

ENCLOSURE 3

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FACSIMILE: (907) 586-2754

CERTIFIED MAIL -- Return Receipt Requested

April 17, 1991

Mr. David L. Bowler
Division Manager
Conoco, Inc.
3201 C Street, Suite 200
Anchorage, AK 99503

Dear Mr. Bowler:

The review process of the Conoco and Oxy USA applications for royalty reduction from 20 percent to 5 percent on the Milne Point Unit Kuparuk production has concluded. Based on the failure to show any net public benefit, I am denying these applications for royalty reduction.

The extensive records on these applications indicate that the profitability of the Milne Point Unit has not achieved the companies' desired level. However, the State as a royalty owner has no authority or responsibility to guarantee the success or profitability of a leasee's investment decisions.

The State of Alaska has given this marginal oilfield significant help by severance tax relief; a further grant of up to \$100 million through royalty relief is not warranted. The State as a royalty owner will not share in the risk of the companies' decisions.

However, there are a couple circumstances in which it may be in the public interest for the royalty owner to reduce its share of the current production to gain a long-term payback benefit.

At some point in an oilfield's later life the production revenue (excluding the royalty barrels) will not be sufficient to cover all the cash costs and operations may cease absent royalty reduction. This is not the current situation in the Milne Point Unit where production revenues from the Kuparuk formation are at the \$4-to-5-million per month level compared to operating costs of \$1-to-1.5 million per month. This circumstance of reaching the "economic limit" of production operations is projected by the companies to occur in a couple decades and can be considered at that time.

A second circumstance in which a royalty owner may choose to help the producer is to encourage further investment that has a direct net benefit to the state. In this situation, the data does not

Enclosure 3

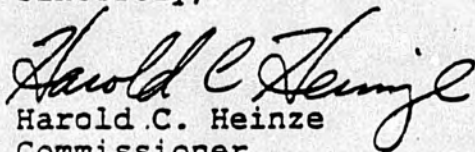
Mr. David L. Bowler

- 2 -

April 17, 1991

indicate that increasing profitability through a royalty reduction would result in an incremental prospective investment that could have an incremental direct benefit to the State large enough to offset the royalty loss. While this circumstance may occur in the future, the current submittal asks the State to give up over 5 million barrels of royalty oil for a potential reward replacing only a few percent of that loss.

Sincerely,


Harold C. Heinze
Commissioner

cc: John Tillinghast, Attorney
Birch, Horton, Bittner & Cherot
James Eason, Director
Division of Oil and Gas

DECISION OF THE COMMISSIONER
ON CONOCO'S APPLICATION FOR ROYALTY REDUCTION

Conoco, Inc. submitted an application to the State of Alaska Department of Natural Resources (DNR). That application requested that the State's royalty share of oil and gas produced from the Kuparuk River formation underlying five Milne Point leases be reduced from twenty percent to five percent.

Conoco's application was analyzed by the staff of the Division of Oil and Gas. Mark Myers, Petroleum Geologist, conducted a public hearing on the application, then prepared a Recommended Decision on Conoco's application. The Recommended Decision was accompanied by, and incorporated by reference, an economic analysis of the application prepared by Edward Phillips, Petroleum Economist (retired).

Normally, the Commissioner of the DNR would act on a recommended decision without further input from Conoco. However, Conoco requested and was granted thirty days in which to comment on the Recommended Decision. Conoco's comments consisted of fifty-one pages of text and twenty pages of affidavits, all of which have now been reviewed by this Commissioner.

As Commissioner, I hereby adopt the Recommended Decision as the final decision of DNR, subject to the additional findings and conclusions set forth in the remainder of this Final Decision.

In this Final Decision I do not undertake to address every alleged fact and argument raised by Conoco in its final comments. The bulk of Conoco's final comments simply state alleged facts and arguments which the hearing officer found inaccurate, unsupported,

or unpersuasive in his Recommended Decision, and which I, too, find inaccurate, unsupported, and unpersuasive. However, portions of Conoco's final comments suggest basic misunderstandings which may be cleared up by a few short words here.

First, the Milne Point Unit Agreement is not an agreement between the State of Alaska and Conoco. It is an agreement between all parties owning a working interest or overriding royalty interest in any lease within the Milne Point Unit. The State of Alaska is not a party to the Unit Agreement; rather, it simply approved the Agreement, subject to certain non-negotiable conditions. Conoco's allegation that paragraphs 1 (Enabling Act and Regulations), 14 (Royalty Settlement), and 18(h)(8) (Reduction of Royalty) of the Unit Agreement were the result of intricate negotiations between the State of Alaska and Conoco is not supported by the record. Nor is Conoco's allegation of linkage between paragraph 14 (increasing the royalty rate from 12.5 percent to 20 percent) and paragraph 18(h)(8) (limiting the availability of royalty reduction).

Second, pursuant to paragraph 14 of the Milne Point Unit Agreement, only five of the leases within the Milne Point Unit are burdened with a twenty percent royalty rate.¹ The remaining leases within the Unit have a 12.5% royalty rate. But paragraph 18(h)(8) of the Milne Point Unit Agreement, by its terms, applies equally to all applications for royalty reduction, whether the royalty rate of the subject leases is 12.5 percent or 20 percent. If there was the

¹ These five leases would have expired for failure to drill but for the State's approval of the Milne Point Unit Agreement.

linkage between paragraphs 14 and 18(h)(8) which Conoco suggests, then I would expect paragraph 18(h)(8) to set forth two sets of criteria for royalty reduction, one applicable to leases with a 12.5 percent royalty rate, and another for leases with a 20% royalty rate.

Third, while the Milne Point Unit Agreement may be the only unit agreement which provides for a royalty rate of twenty percent, numerous oil and gas leases issued during the time period in which the Milne Point Unit Agreement was approved also provide for a twenty percent royalty rate. No special provision was made by statute, regulation, agreement, or lease to treat differently applications for royalty reduction on leases bearing a twenty percent royalty rate from applications for royalty reduction on leases bearing a 12.5 percent royalty rate.

Fourth, even if paragraph 18(h)(8) of the Milne Point Unit Agreement governed Conoco's application (AS 38.05.180(j) and (p) having no force or effect), paragraph 18(h)(8): (a) makes relief discretionary, and (b) requires a clear showing by Conoco that the revenue from all oil and gas produced from the field is insufficient to produce a reasonable rate of return on Conoco's total investment in the field. Following the reasoning set forth in the Recommended Decision, I find that: (a) it would be an abuse of my discretion to grant the royalty reduction requested because it is not in the public interest, and (b) Conoco has failed to make

a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field.

Fifth, AS 38.05.180(j) is not being applied retroactively. It was incorporated by reference in the Milne Point Unit Agreement. It is being applied to an application submitted after the statute's effective date. And it did not materially and adversely impact Conoco such as to constitute an impairment of contract.

Sixth, footnote 15 of Conoco's comments indicates that the Recommended Decision used as a reasonable rate of return "current T-Bill rates, which are ... 2.4% in real terms." In fact, the Recommended Decision used as a reasonable rate of return the average of the Treasury Bill rates for the life of the Milne Point Unit (1980-1989), which average rate approximates six percent per annum in real terms.

Seventh, when Conoco submitted an application for royalty reduction in 1985, it requested relief under AS 38.05.180(p). AS 38.05.180(p) does not require two years production before relief can be granted. However, Conoco's application was also burdened by the requirements of paragraph 18(h)(8) of the Milne Point Unit Agreement. That paragraph requires two years of production before royalty reduction can be granted. Conoco had not produced for two years from the Milne Point Unit until February 1990. Therefore, if for no other reason, Conoco's 1985 application had to be denied because Conoco had not then produced for two years.

Eighth, public utility law and oil and gas law can be distinguished on grounds other than the costs of capital for utilities and oil and gas producers. A public utility often has a single profit center; if its economic return is insufficient, its entire operation may cease. For that reason, public utility law seeks to guarantee a return adequate to assure continuing services from what is often the sole source for those services. Conversely, the major oil producers, including Conoco, have multiple profit centers. Should Conoco fail to obtain what it considers to be an adequate return on a single profit center--such as the Milne Point Unit--Conoco's other more-profitable ventures virtually assure Conoco's continued existence. But even if Conoco failed to survive, the public's supply of oil and gas is not dependent on a single producer. Therefore, neither this State's oil and gas leases nor the royalty reduction statutes need guarantee an oil producer a specific rate of return, or any return at all. I find that no guarantee of a rate of return was intended by the legislative or executive branches of this State's government.

In addition to clarifying the foregoing matters, I hereby supplement the Recommended Decision's public interest finding. Contrary to the assertions of Conoco, the public interest finding did not simply weigh cash gains and losses to the state government. The Recommended Decision determined that lost revenues to the state government would be approximately four times greater than the sum of additional royalties to the state government plus the total

value of the increase in production assured by royalty reduction.² The Recommended Decision also gave weight to additional, though speculative, production which may result from the royalty reduction. However, the Recommended Decision did not specifically or fully address certain feasible benefits of royalty reduction, probably due to their speculative and minute nature. These benefits include the following:

First, if future seismic acquisition and interpretation supports Conoco's current geologic mapping, and the State reduces its royalty to five percent, Conoco will drill two additional production wells which, based on Conoco's expectations, would produce approximately 3 million additional barrels of oil (chance factor times estimated reserves in the two largest fault blocks). This places the maximum possible additional benefit produced by the royalty reduction at 4.2 million barrels (3 million barrels of new

² The Recommended Decision, at page 13, states:

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is \$12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose \$64,000,000 in royalties on oil produced during the next twenty-two years, and gain \$720,000 in royalties on oil produced twenty-two to twenty-five years from now. Total recovery of additional production under a reduced royalty rate is estimated to be 1.2 million barrels of oil valued at \$14,400,000.

Assuming that the average wellhead value is \$22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose \$109,000,000 in royalties on oil produced during the next twenty-two years, and gain \$1,220,000 in royalties on oil produced twenty-two to twenty-five years from now. The total incremental volume of oil that would be achieved through a reduction in this case would be valued at \$26,400,000.

reserves plus 1.2 million barrels due to three extra years of production). The royalty value to the State of the speculative additional 3 million barrels of oil at a \$22 per barrel well head value is approximately \$3.3 million. Consequently, if royalty reduction was granted, the State would forego \$109 million in royalties to gain up to \$4.5 million in royalties from additional production.

Second, royalty reduction is virtually certain to increase production by 1.2 million barrels, and may increase it by an additional 3 million barrels. The Trans-Alaska Pipeline transports 2 million barrel per day. One million, two-hundred thousand barrels would fill the line for 14.4 hours. Three million barrels would fill the line for 36 hours. The sum of the two volumes would fill the line for just 50.4 hours.

Third, additional production from the Milne Point Unit could mean additional jobs. Based on Conoco's statement that it may be able to increase production in the event of a royalty reduction by drilling two additional wells, I estimate that no more than thirty additional workers would be employed for a period no greater than one month.

In weighing the costs and benefits of royalty reduction, foregone royalties, additional royalties, and additional production can be quantified, at least in a relative sense. Assigning dollar values to pipeline fill and additional jobs is more difficult. Yet clearly these benefits are insufficient to overcome the phenomenal costs of granting the royalty reduction requested by Conoco.

Therefore, even after considering benefits not quantified or expressly addressed in the Recommended Decision, I conclude that it is not in the public interest to grant the royalty reduction requested by Conoco.

Subject to the foregoing, the Recommended Decision on Conoco's application for royalty reduction for the Milne Point Unit is hereby adopted as the Final Decision of the Department of Natural Resources.

STATE OF ALASKA, DEPARTMENT OF
NATURAL RESOURCES

Dated: _____

4/21/91

Harold C. Heinze
Harold C. Heinze, Commissioner

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

To: Harold C. Heinze
Commissioner

Date: December 28, 1990

Phone: 907/762-2588

From: Mark Myers
Geologist

Subject: **Recommended Decision**
and Finding for Conoco's
Royalty Reduction
Application, Milne Point
Field

Under my delegation as the department hearing officer, I am enclosing the recommendation and finding concerning Conoco's application for a royalty reduction from 20% to 5% for the Milne Point Field. As requested, in your conversation with Jim Eason, I have not enclosed Appendix 1 which contains confidential financial data furnished by Conoco. Appendix 1 is available at the Division of Oil and Gas should you wish to review this data and technical analysis of Conoco's request.

I will be on personal leave from December 31 through January 4. Please feel free to contact me at your convenience, should you have any questions.

Enclosure

1

**RECOMMENDED DECISION OF THE COMMISSIONER OF
NATURAL RESOURCES REGARDING THE CONOCO
APPLICATION FOR ROYALTY REDUCTION ON ADL 47433,
47434, 47437, 47438, AND 28231 (KUPARUK
PARTICIPATING AREA: MILNE POINT UNIT).**

12/28/90

Finding and Recommendation

Conoco has applied for a reduction of its royalty from 20 percent to five percent on Kuparuk Formation oil produced from the Milne Point Unit. Given the short history of the field, the information provided in Conoco's application and its public comments on the application fail to: (1) provide a clear showing that its revenue over time will not allow for a reasonable rate of return; (2) demonstrate with any certainty that the requested reduction will significantly prolong the life of the field; or (3) demonstrate that the requested reduction would secure the proper protection of the public interest.

A clear showing of a failure to achieve a pre-determined rate of return over time requires accurate forecasting of oil prices over nearly two decades, as well as a clearer understanding of the potential total production from Milne Point, both with and without royalty reduction, than is currently available. The difficulty of reliably quantifying the latter is demonstrated by Conoco's reported decision to proceed shortly with Schrader Bluff production with the goal of ultimately tripling average daily production from the unit. On its face, it is difficult to argue the need for royalty relief at this time for a field which pays no severance tax, and for which the economics will be dramatically altered in the very near future by the operator's decision to pursue development of these shallow oil sands.

You have the discretion to approve a royalty reduction when it is determined to be in the state's best interest. However, our analysis of the potential benefits which may be gained years hence from the forbearance of substantial state royalties for the next twenty years or so, does not

appear to support such a finding in Conoco's case. For the reasons discussed more fully both below in the accompanying confidential Appendix 1, I recommend that you deny Conoco's application on these bases.

The department's analysis of Conoco's application clearly illustrates the need for a policy that limits royalty relief to those instances where sufficient objective factual data, including production revenues and development expenses, are available to establish that the reduction of the state's royalty share will both prolong production and result in benefits which are demonstrably in the state's interest. In addition to maintaining a continuous, though reduced, royalty stream, those benefits could include continued employment, additional capital investments in wells and production facilities (to increase the total recovery of oil from the field) and other factors.

Although Conoco's application fails to make a clear showing of its inability to achieve a reasonable rate of return over time or of being in the state's best interest, our review of its application did point out several concerns common to any application for royalty reduction under the existing statutes. These include defining "reasonable rate of return" consistently and objectively for royalty reduction purposes, and structuring any reduction so as to be effective in achieving the desired results without unduly diminishing the state's royalty interest.

Based upon our analysis and using Conoco's application as an example, I recommend an alternative approach from that advocated by Conoco for setting a reasonable rate of return, and provide documentation to support the use of such a standard for evaluating future applications. If you agree with the use of the rate of return test which is suggested, I recommend that the division prepare appropriate draft regulations and notice them for public comment and hearing so that future applicants who may be affected have the opportunity to comment on the draft regulations.

I. Background and Introduction

Conoco Inc. has applied for a reduction of the State of Alaska's royalty interest in oil and gas production from the Kuparuk River Participating Area of the Milne Point Unit. In its application, Conoco requests that the State's royalty interest in its production from the Kuparuk Formation only, underlying ADLs 47433, 47434, 47437, 47438, and 28231, be reduced from 20% to 5%. Conoco has not requested a royalty reduction for production from the Schrader Bluff Formation, which lies above the Kuparuk Formation throughout much of the Milne Point Unit.

Conoco submitted its formal application for royalty reduction in February 1990. However, the application was not determined to be substantially complete until July 1990. As provided for under 11 AAC 83.185, a public hearing on the application was conducted by the department on August 28, 1990. Conoco continued to submit documents in support of its application through October 9, 1990. Conoco's application has been evaluated under, alternatively, AS 38.05.180(p), AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Conoco's application was submitted, and AS 38.05.180(j), as amended in 1990 by HB 128, effective September 12, 1990.

Two key terms used in these statutes need to be clearly defined in order to make a royalty reduction determination. These terms are discussed in Parts II, III, and IV. Part III defines "field," as used in the royalty reduction context. Part IV analyzes what constitutes a "reasonable rate of return." Part V specifies why a decision to grant royalty relief is discretionary, not mandatory. Parts VI, VII, and VIII address each of the three statutory provisions listed above, as they apply to Conoco's application. Part IX refutes Conoco's assertion that Paragraph 18(h)(8) of the Milne Point Unit Agreement controls disposition of its application for a royalty reduction. Finally, this document concludes with a brief summary of this finding and recommendation.

This document is accompanied by Appendix 1, an economic analysis of rates of return, the cost of capital, Conoco's confidential financial data, and the costs to the state of a royalty reduction as proposed by Conoco in this instance. Appendix 1 was prepared by Ed Phillips, Petroleum Economist (retired) for the Division of

Oil and Gas. Although Appendix 1 supports the conclusions reached herein, it cannot be part of the public record of this recommended decision. It must remain confidential due to its extensive references to Conoco's proprietary information and data which are entitled to confidentiality under state statutes.

II. Definitions

Two key terms used in the statutes need to be clearly defined in order to make a royalty reduction determination. These terms are **reasonable rate of return**, and **field**. Since these terms lack statutory definitions for the purposes of royalty reduction, and since no previous requests for royalty reduction have been granted, these terms are examined with respect to this application. In its August 27, 1990 supplemental brief Conoco attempted to define the terms **reasonable rate of return** and **field** and presented arguments why the department should be bound by the definitions in its review of Conoco's application. The following two sections will explain why, in my opinion, Conoco's proposed definitions are inappropriate and must be rejected. Additionally, these sections will provide alternative definitions of these terms and demonstrate why these definitions are appropriate for royalty reduction analyses.

III. Definition of a Field

AS 38.05.180(j), before and after amendment by H.B. 128, and paragraph 18(h)(8) of the Milne Point Unit Agreement restrict royalty relief to instances in which the **"field"** would not otherwise produce a reasonable rate of return. AS 38.05.180(j) before amendment also requires that the relief prolong **"field"** life. AS 38.05.180(j) after amendment by H.B. 128 requires that either the relief be necessary to prolong **"field"** life or restore shut-in production. Neither the royalty reduction statutes or the Unit Agreement define **"field."**

Conoco, in its supplemental brief submitted on August 27, 1990, stated its belief that, for the purpose of royalty reduction, the Milne Point leases contain two separate oil fields, the Kuparuk River and Schrader Bluff **"Fields."** It based its argument on the fact that the two oil pools are vertically separated, have different reservoir properties, and will require

different production techniques. Additionally, Conoco's brief states that the definition it offers is identical to the definition of "field" used in Texas oil and gas law. Conoco's argument for considering the Schrader Bluff and Kuparuk River oil pools as separate fields is summarized by the following statement: "Geologically distinct fields will also be economically distinct, and therefore of little utility in assessing the economics of each other." (Supplemental Brief of Conoco and Oxy USA Inc. p.25).

To support its interpretation of the definition of "field" Conoco referenced *Wotton v. Bush*, 261 P.2d 256 (Cal. 1953), in which for the purpose of well spacing requirements, an administrative officer of the California Division of Oil and Gas testified that "a field has come to be considered as that expanded area from the region of initial production to the limits of productivity in all lateral directions; and that within a given field there was no structural connection or drainage to or from other fields." It should also be noted that unlike Milne Point, the fields in the *Wotton* case were geographically (laterally) separated and not at different depths on the same leases. The *Wotton* case dealt with the issue of well spacing requirements. Appropriate well spacing is ideally determined by internal reservoir properties including porosity, permeability, heterogeneity, viscosity of oil, reservoir thickness, reservoir pressure, fluid contacts, and other factors. These properties are certainly unique to each pool and/or reservoir and often vary within the same pool or reservoir. A definition of "field" that is applicable for determining production rates, well spacing, participating areas, internal company development plans, tax credit for enhanced oil recovery, etc. may not be applicable or even appropriate to royalty reduction. This is the case with the definition proposed by Conoco.

Conoco argues that its definition is consistent with that used by industry. However, this argument is not persuasive since there is no consistent use of the term "field" within industry. For example, the Kuparuk River Formation within the Kuparuk River Oil Field consists of two separate reservoir intervals, the A and C sands of different geologic age (Valanginian vs. Hauterivian). Additionally, the sands are vertically separated by a major regional unconformity, were deposited in different

6/

depositional settings, and have very different reservoir properties. In spite of these different properties neither industry nor the State differentiates these producing intervals when they refer to the Kuparuk River Oil Field.

For the purpose of royalty reduction, the department must define "field" in a matter that: (1) is consistent with the intent of the royalty reduction statutes, regulations, and, to the extent feasible, the Milne Point Unit Agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

A royalty reduction application under AS 38.05.180(j) must comply with 11 AAC 83.185, which requires the application to:

... (2) state location and status of all past and present activities on the lease; (3) include a detailed report of all production during the six months preceding the filing of the application; (4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease.

(Emphasis added). This regulation evidences the department's interpretation of "field" as clearly referring to all reservoirs underlying the lease.

This interpretation is consistent with earlier comments in a October 9, 1984 letter to Conoco from Division of Oil and Gas Director Kay Brown in which she stated, "the division has no statutory definition of 'field'..." and listed three possible geologic definitions of "field." "Field may refer (1) to a common source of supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs...."

Further support for the department's interpretation of "field" comes from the definition of "field" used by another state regulatory agency, the Alaska Oil and Gas Conservation Commission (AOGCC). While AOGCC's

definition of "field" does not govern an application for royalty reduction, it is indicative of a definition accepted by industry in some settings. For the AOGCC, "field" is defined by AS 31.05.170(5), which states:

"field" means a general area which is underlain or appears to be underlain by at least one pool, and includes the underground reservoir containing oil and gas; and the words "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" unlike "pool" may relate to two or more pools...

For the purpose of royalty reduction requests, the department defines "field" as encompassing the lateral limits of productivity of all reservoirs or pools within the Milne Point Unit regardless of vertical stratification of reservoirs or pools underlying a lease or leases. This definition meets the standards set out earlier: (1) is consistent with the intent of the royalty reduction statutes, regulations, and to the extent feasible, the Milne Point Unit agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

This definition allows the department to consider all the relevant information with regard to royalty reduction. Commonality of production and transportation facilities and well bores, as well as shared information and economy of scale provided by having multiple stacked reservoirs under a single lease are important factors in the development of an oil field. Not only do multiple stacked reservoirs have lower development costs, but their development also entails lower risk wells. For example, wells can be plugged back and produced from the shallower horizon, if the deeper horizon is not produced due to faulting, lack of net pay, well bore damage, depletion or other factors. The department's definition of "field" is similar to that used by AOGCC in that it considers multiple vertically separated pools or reservoirs underlying the same lease or leases a single "field."

Utilizing a definition that encompasses all reservoirs or pools within the Milne Point Unit also helps minimize the incentive for the operator and lessees to manipulate production and/or costs from individual reservoirs within the Unit for the purposes of affecting royalty reduction applications.

Note that the department's definition does not prohibit the commissioner from granting selective relief to individual pools or reservoirs, or even individual leases. In this case, the ability to do so is clearly stated by the Milne Point Unit Agreement and not prohibited by statute.

IV. Definition of Reasonable Rate of Return

Similarly, regardless of whether one is guided by State law or the Milne Point Unit Agreement, there is the potential for serious disagreement between the applicant and the department regarding what constitutes "a reasonable rate of return" for the purpose of evaluating a royalty reduction request. Without providing objective standards, both AS 38.05.180(j) and the Milne Point Unit Agreement leave it up to the commissioner to define a reasonable rate of return for royalty reduction purposes. Against this backdrop, the department has an obligation to adopt a standard that is objective and which may be applied consistently without regard to the vagaries of the financial planning standards of individual companies. Furthermore, the standard should provide a positive real rate of return (more than inflation), yet not allow for excessive profit at the expense of the state's royalty share.

Conoco has argued in its August 27, 1990 supplemental brief and in testimony at the public hearing, that, at a minimum, a reasonable rate of return, for royalty reduction, should be defined as the cost of capital to the company plus a marginal profit. There are obvious problems with this standard. First of all, such a standard would vary widely from company to company. Of the eight major North Slope producers examined, Conoco had the highest cost of capital at a nominal rate of 12.75%. Based upon information available to the department, other North Slope producers' cost of capital ranged from a low of 9.26% (Oxy) to a high of 10.26% (ARCO). Additionally, proprietary financial data of this sort are generally

not directly available to the public, rates are difficult to monitor over time, and many projects are internally financed by the companies.

Thus, defining a reasonable rate of return standard as the individual firm's cost of capital is not acceptable since it treats every firm differently. Such a standard would provide a different level of relief based upon the company, regardless of the field. To protect the state's interest, royalty relief should be based on the economics of the field and not on a company's real or perceived internal financial characteristics. Further, the standard should be impartially applicable to all lessees. A reasonable rate of return that is independent of the particular company financing involved should be adopted to avoid possible manipulation of in-house economics simply for royalty reduction purposes.

In its August 27, 1990 supplemental brief, Conoco cites a number of public utilities law cases in support of its proposed definition of rate of return. These cases are intended to demonstrate examples where the most strict standard for a reasonable rate of return is the cost of capital. However, for royalty reduction purposes, these are invalid analogs. A public utility is granted a rather generous (but capped) rate of return since it is regulated and at the same time must compete with unregulated firms in the capital market. Also, a public utility does not have an opportunity to make large profits in other settings, as does a large, privately owned integrated oil company such as Conoco. Neither Conoco's prices nor its costs are regulated by a public agency therefore, Conoco has no regulated limits on its potential profitability.

It is the potential for large profits that allows Conoco, or any other oil and gas lessee for that matter, to take the risks inherent in wildcat exploration and oil field development. This provides a freedom of operation not granted to a public utility. It is therefore only proper that a more conservative standard for rate of return be applied to Conoco, and other lessees, in determining whether, and to what extent, a reduction in the state's royalty share of production is appropriate. When all the arguments are stripped away, the stated purposes of the royalty reduction statutes are to prolong the economic life of the field and protect the public interest, not

to guarantee the state's lessees a minimum rate of return on every field which they choose to develop.

Standards other than those suggested by Conoco are available to define a reasonable rate of return. For example, the economic yardstick used by the United States Geologic Survey and the U.S. Department of Energy in recent studies has been an after-tax rate of return of 8%. Referring to the development of North Slope reserves in *Economics and the National Oil and Gas Assessment, The Case of Onshore Northern Alaska* (In press Attanasi, Bird, and Mast) the authors state "Fields were considered commercially developable if a discounted cash flow analysis showed that an after-tax return of 8 percent could be achieved. At the time of the assessment, the 8 percent hurdle rate was being used by the U.S. Department of Energy's Energy Information Administration in the national energy base case forecasts (Jon Rasmussen, Energy Information Administration, oral communication)."

Another potential yardstick for defining a reasonable rate of return is the standard used by the State of Alaska Department of Revenue (DOR) in determining reasonable shipping rates for North Slope crude for the purpose of calculating severance tax obligations. Shippers are allowed the Gross National Product deflator (GNPd) plus two percentage points return to capital as allowable expenses (profits). For the 1980-1989 period, the GNPd fell short of the 90 day Treasury bill rate by 4.4 percentage points. Otherwise stated, DOR has allowed, as a reasonable rate of return, a rate which is, on average, 2.4 percentage points less than the 90 day Treasury bill rate.

The standard which I recommend the department choose to define a "reasonable rate of return" for the purposes of this application is the rate of return for a 90 day Treasury Bill. The basis for this recommendation is more fully set out in the text of Appendix 1. For the period of 1980-1989 the real rate of return for the 90 day bill was approximately six percent. This standard compares favorably with other potential standards examined by the department.

V. Discretionary Nature of Royalty Reduction

A well established rule of interpretation specifies that "may" refers to discretionary action, while "shall" dictates mandatory action. Similarly, "may not" constitutes a mandatory prohibition.

AS 38.05.180(p) states the commissioner "may ... change ... royalty requirements" Paragraph 18(h)(8) of the Milne Point Unit Agreement provides that the State "may reduce Lessee's obligation to pay royalty" Thus, both AS 38.05.180(p) and paragraph 18(h)(8) of the Milne Point Unit Agreement permit royalty reductions, but they do not mandate royalty reductions, except where a denial of a royalty reduction would be arbitrary or unreasonable.

AS 38.05.180(j), both before and after amendment by HB 128, mandates promulgation of regulations governing applications for royalty reduction: "the commissioner shall adopt regulations" However, the regulations are "to allow reduction of royalty" The word "allow," like "may," is permissive, not mandatory. AS 38.05.180(j), both before and after amendment by HB 128, then uses mandatory language to specify one instance in which royalty reduction is not allowed: "The commissioner may not grant a reduction of royalty" unless the applicant has made a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field. In short, while AS 38.05.180(j) contains some compulsory directives, it also permits denial of an application where not unreasonable or arbitrary to do so.

VI. Evaluation of Application Under AS 38.05.180(p)

AS 38.05.180(p) states:

To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation

of the pool, field or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as the commissioner determines necessary or proper to secure the proper protection of the public interest.

(Emphasis added).

Conoco's application, as initially submitted, represented that the Milne Point Unit Kuparuk Formation had an expected field life of twenty-five years, three years of which have almost elapsed. The original application did not indicate that the field life would be lengthened, or more oil produced, should Conoco be granted the royalty relief requested. Subsequently, Conoco amended its application, to clarify that if the State reduced its royalty to 5%, Conoco would produce 1.2 million barrels more than it would otherwise produce in the three years following the first twenty-five years of production.

In evaluating Conoco's application, the department must determine whether the public interest would best be served by the State's receipt of a 20% royalty over a remaining field life of twenty-two years, or by the State's receipt of a 5% royalty over a remaining field life of twenty-five years and the production of an additional 1.2 million barrels of oil twenty-two to twenty-five years from now. This determination cannot be made without reference to the wellhead value of Milne Point oil.

It is impossible to accurately calculate the wellhead value of production occurring over the next twenty-two to twenty-five years. The impossibility of the task is exemplified by the wide range of values for oil produced from the Kuparuk Formation in the Milne Point Unit in 1990 alone, when the reported wellhead value tripled between July and September. However, the department is able to model the effects in a gross sense by selecting a low estimated average value and a high estimated average value, then calculating the costs and benefits of granting the requested royalty reduction should values approaching either of these extremes prove accurate.