BP Cherry Point Cogen
DEIS Comment - 17

GERALD STEEL, PE
ATTORNEY-AT-LAW
2545 NE 95th STREET
SEATTLE, WA 98115
Tel/fax (206) 529-8373

October 30, 2003

RECEIVED
OCT 31 2003
ENERGY FACILITY SITE
EVALUATION COUNCIL

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Re: BP Cherry Point DEIS Comments

Dear Mr. Fiksdal:

On behalf of the Washington State Association of Plumbers & Steamfitters (WSAPS), I write this letter to comment on the BP Cherry Point Cogeneration Project DEIS. This power generation facility is not required to meet the region's reasonable need for additional electricity generation. Exhibit 1 at 1-2. Therefore the FEIS should indicate that the project should not be approved if there are probable significant adverse environmental direct, indirect or cumulative impacts. The DEIS fails to meet the requirements of WAC 197-11-440 in that it fails to summarize significant impacts that can not or will not be mitigated. This should be corrected in the FEIS. 1

WSAPS hereby submits 23 pages of comments (Exhibit 1 hereto) made by their environmental expert consultant, John Williams. Mr. Williams Statement of Qualifications is provided as Exhibit 2. Exhibit 1 raises issues that must be addressed in the FEIS. WSAPS incorporates by reference in this letter any additional DEIS comments timely-submitted by Mr. Williams after the date of this letter.

One troubling feature of the DEIS is the statement in many places that impacts from the project cannot be determined from the information available. For example, in Section 1.8.1, the DEIS states, "it is not possible to determine their actual impact on global warming." As 2
another example, in Section 3.6.1, the DEIS indicates that inadequate information exists to determine the full extent of Category I and Category II prime agricultural soils that will be impacted by this project. Under SEPA if the agency proceeds in the face of uncertainty, the environmental documents need to provide a worst case analysis to the extent that this 3
information can reasonably be developed. WAC 197-11-080. The author of the DEIS should review the DEIS for each place where there is uncertainty about impacts and seek to provide a worst-case analysis.

Allen Fiksdal, Manager
October 30, 2003
Page 2

Regarding impacts on prime agricultural soils in the Agricultural Protection Overlay, the EIS should include, as an alternative, a site with less impact to prime agricultural soils. The impacted soils are not only those soils on the project site, but also soils that are in the vicinity that will be impacted by increased levels of pollution and reduced water availability. The impact of the proposed project on prime agricultural lands in the local microclimate area should be found to be a significant impact with the project as proposed. **4**

Regarding water use, the amount of water proposed to be used by this project should be considered a significant impact. It is inappropriate to consider the impact to be negligible because of the potential shutdown of the Alcoa Intalco Works which is unrelated to this project. The Alcoa Intalco Works does not consume the water that it uses while this project coverts nearly all of its water to steam that is lost to the local microsystem. The impact of water from the facility with elevated salt concentrations being discharged in agricultural areas has not been adequately addressed in the DEIS **5**

The impact on visibility in the Olympic National Forest should be considered significant. This is a single project that is reducing visibility for hours each year. This is a very significant impact on visibility to be caused by just one project. Four to five thousand projects of this nature could fully and permanently cut off visibility for large areas of the National Forest. **6**

Very truly yours,

Gerald Steel

PIPE10b30.03

**COMMENTS ON THE DEIS FOR THE BP POWER PLANT**
**PURPOSE AND NEED**

One of the purposes and needs for this project is the need to provide the predicted additional electrical generation capacity for the future needs of the region. This projected need, according to the Northwest Power Planning Council's power forecasts for the region, predicted that by 2015, the needed regional increase in power would range from an additional 2035 megawatts (MW) under the medium prediction, to 4120 MW under medium-high, and 7507 under the high prediction.

However, those predictions are already almost two years old. Since those predictions were made, the following plants have gone on-line:

Chehalis 520 MW
Hermiston 650 MW
Frederickson 250 MW

Coyote #2 280 MW
Springs

Klamath
Cogen 484 MW
expansion 100

Combine Hills 41
SP Newsprint 96
small projects 100

TOTAL 2521 MW 1(1)

In other words, enough facilities with "firm" power generation have already been constructed to provide far more energy what would be needed for the next ten years under the "medium" prediction. In addition, another 519 MW of non-firm wind generating capacity have also been constructed.

(WIND)
Stateline 119 MW
Stateline II 37
Klondike 24
Condon 50
Transalta 200
Nine Canyon 48
Vancycle 41

TOTAL 519 MW

Page 1 of 23

Exhibit 1

The following plants are partly constructed:

| | |
|---|---|
| Goldendale | 250 |
| Mint Farm | 300 |
| Satsop | 650 |
| TOTAL 1200 MW | |

At this point, the region has enough new energy facilities already running, and under construction, to meet the medium-high prediction for needed energy capacity for the next twelve years, and for the next 22 years under the medium energy needs prediction.

ALREADY PERMITTED

| | |
|---|---|
| Sumas II | 660 |
| Wallula | 1300 |
| Umatilla | 600 |
| PGE | 560 |
| Port Westward | 600 |
| Plymouth | 300 |
| Col. River En. | 44 |
| Ore. Eng. | 93 |
| Boise/StH | 141 |
| West Linn | 94 |
| TOTAL 4400 MW | |

**TOTAL RECENTLY COMMISSIONED, RUNNING, UNDER CONSTRUCTION, AND ALREADY PERMITTED: 8100 MW.** 1(1) cont.

In summary there is already enough new energy generation built, under construction, and fully permitted, to supply even the highest prediction of new energy need for the next twelve years, and the medium-high prediction for the next 22 years, **without the BP project**.[1] These figures do not even take into consideration the thousands of megawatts of additional projects that are even now seeking permits, including but not limited to the Wanapa project, Calpine/Turner, Peoples Energy/Klamath Falls, and Coburg, which collectively add to another 3500 MW in capacity.

**CONCLUSION**

The DEIS fails to demonstrate a need for a 720 MW plant at BP to meet regional energy needs

---

[1]The DEIS at Table 3-26 features a partial list of newly commissioned thermal plants, plants under construction, and plants fully permitted which totals 6504 MW. The DEIS list considerably underestimates the amount of current, under-construction and fully permitted generation, for instance by misstating the production of HPP, which is 649 MW, not 546 as claimed in the DEIS.

for the next 22 years.

**ALTERNATIVE SIZE**

One alternative that was rejected without an adequate discussion would be sizing the power plant to supply only the amount of electricity and stream that the refinery can consume.
The DEIS claims that a smaller plant would not provide economic energy, and would be an uncertain steam supplier. But not enough details were supplied to verify this dismissal of an important alternative.

Only an 85 MW plant was considered when this alternative was rejected. A slightly larger plant, for instance 100 or 200 Mw, which would provide more than enough energy for BP, and would also provide considerable excess stream generating capacity, was apparently not studied.
If the plant were smaller, it could still supply its contractual obligations, but there would be less significant impacts, especially air emissions.

For instance, here is a list of several other cogeneration facilities which would supply an extrapolated 510,000 lb/hour of steam that BP needs, without producing the immense amount of air pollution and water use generated by the proposed 720 MW power plant

| NAME OF FACILITY | MW | LB/STEAM/HOUR | Extrapolated* MW/510k lb/STEAM |
|---|---|---|---|
| Sun Mill, Okeelanta, Fla | 75 | 1,300,000 | 29 |
| UW-Madison | 45 | 600,000 | 37 |
| G-P, Camas, Wash. | 11 | 140,000 | 39 |
| Petro Canada | 165 | 1,584,000 | 52 |
| Macay River | | | |
| Hershey's, Oakdale, CA | 5.6 | 50,000 | 56 |
| Scott Paper, Everett, Wa | 47 | 435,000 | 56 |
| NIH | 23 | 180,000 | 64 |
| Coca-Cola Leesburg | 3.6 | 22,000 | 82 |
| Auburndale | 7.2 | 44,000 | 82 |
| UC Berkeley | 24 | 100,000 | 120 |
| Grays Ferry/Trigen | 170 | 800,000 | 106 |
| Aries | 45 | 187,000 | 120 |
| ExxonMobil, Baytown, TX | 160 | 560,000 | 143 |
| United Cogen, SF, CA | 30 | 100,000 | 150 |
| Carseland Cogen | 80 | 264,000 | 152 |
| Solvay/Jemeppe-Sambre | 90 | 286,000 | 158 |
| UW-Madison | 150 | 400,000 | 188 |
| Oxychem, Ingleside, TX | 440 | 1,100,000 | 210 |
| Bear Creek | 80 | 165,000 | 242 |

*This figure is a scaled-up estimate of what megawatt plant would also generate 510,000 lb/hour of steam, given the figures presented for each particular facility. All plants except G-P/Camas

1(2)

and Scott Paper are natural gas fired.

Based on the median generating capacity figure for these cogeneration plants, it can be extrapolated that a 100-200 MW facility is fully capable of generating 510,000 lb/hour of process steam for use at BP. In practice, this approximately sized plant appears to be in common use for steam geneating hosts of this magnitude. At least six plants on the list generate over 510,000 lb/hour of steam and their energy capacity ranges from 45 to 440 Mw. For instance, the Petro Canada, ExxonMobil, and the Gray's Ferry cogeneration plants generate over 1.5 million lb/hour, 560,000 lb/hour, and 800,000 lb/hour of steam while generating 160-170 MW of electricity. 1(2) cont.

This data shows that a far smaller cogeneration plant of only about 20% of the proposed size of the BP plant, would be fully capable of meeting the purpose and need stated in the DEIS, while producing only about 20% of the projected air and water pollution, and water use.

**ALTERNATIVE POLLUTION CONTROL–ELIMINATE AMMONIA THREAT**

The power plant will store anhydrous ammonia, and emit ammonia for use in their SCR air pollution scrubbing system. This present dangers to public health and to air quality. The DEIS should have discussed several alternatives to use of anhydrous ammonia that present far less risk to human health and safety. These alternatives include a non-ammonia scrubber system, use of aqueous ammonia, or use of urea. 1(3)

**AMMONIA STORAGE AND TRANSPORT**

The proposed power plant will use, handle, store and transport large amounts of ammonia. Ammonia is listed on the EPA's list of extremely hazardous chemicals. The State of Louisiana has recently tightened regulations governing handling of ammonia.
It is prudent to minimize the use and storage of any hazardous chemicals such as ammonia. Nonetheless, BP proposes to transport, use and store large quantities of ammonia on site.

The DEIS is deficient in failing to describe and address the possible consequences of transporting, piping, storing and emitting hundreds of thousands of pounds of ammonia at this facility every year. There are two issues regarding ammonia. The first issue is the constant release of ammonia from this facility under normal operating conditions. The second issue is the risk of ammonia releases from the storage and transportation of this hazardous chemical. 1(4)

**AMMONIA EMISSIONS UNDER NORMAL OPERATING CONDITIONS**

Ammonia may be emitted from the project at 5 parts per million (ppm) which is one/half of the odor threshold. There are other ammonia sources in this area, including other power plants, whose emissions could contribute to an ambient ammonia level. These other ammonia sources were not evaluated in the DEIS. In this case it is possible that the ammonia odor threshold could be exceeded under adverse air quality mixing conditions, such as inversions. These nearby ammonia sources should have been inventoried, because those sources may cumulatively contribute to formation of secondary particulate. 1(5)

But no controls for ammonia are discussed, nor is there any modeling that accounts for potential ambient levels of ammonia that would cumulatively join with the proposed facility's emissions. The impacts of ammonia emissions on PM formation were discussed earlier. 1(5) cont.

**NON AMMONIA SCRUBBER SYSTEM--BENEFITS OF SCONOx WERE NOT ADEQUATELY CONSIDERED**

SCONOX is an alternative pollution scrubbing system that does not use ammonia. SCONOX should have been comprehensively discussed as an alternative to the proposed project. The SCR system proposed for use by the Applicants results in a number of environmental problems that are reduced or eliminated with the use of SCONOx. These problems include: (1) hazards from accidental releases of the ammonia used in the SCR system during its transportation and handling; (2) the formation of particulate matter from the oxidation of $SO_2$ in the SCR catalyst; (3) the formation of particulate matter from reactions between ammonia and $SO_2$; (4) generation and disposal of the hazardous SCR catalyst at the end of its useful life; (5) inability to control NOx and CO emissions during startups and shutdowns; (6) increase in $NO_2$ from the use of dry low NOx combustor.

SCONOX would produce greater control of NOX and other pollutants, and eliminate ammonia emissions, and the threat of releases from storage and transport of ammonia. The EPA has recently ruled that SCONOX is considered technically "Available" for NOX control on natural gas fired turbine power plants. The SCONOX controls on two UC-San Diego Solar 130S turbines, control NOx to 1.0 ppm or below, and also control CO to below .04 ppm, according to San Diego Air pollution Control District Source tests. 1(6)

Although the DEIS rejected SCONOX based on cost, the California Air Resources Board BACT evaluation comparison reports for combustion turbines, rated SCONOX as only slightly more expensive than SCR.

**LOW NOX BURNERS**

The newest generation of low-NOx burners appropriate for power plants can reportedly lower NOx emissions to below 5 ppm, without using ammonia and producing ammonia emissions and crating the hazards of ammonia storage and transport. The DEIS should have discussed these devices.

**$PM_{10}$ FORMATION CAUSES VISIBILITY REDUCTION**

The fact that ammonia/PM reactions actually occur and cause visibility impacts is well documented in the technical literature. A noted atmospheric textbook, for example, contains this vivid description of the problem ( Pitts and Pitts, 1999, [2] p. 284):

> "The formation of ammonium nitrate has some interesting implications for visibility

[2] Barbara J. Finlayson-Pitts and James N. Pitts, Jr., Chemistry of the Upper and Lower Atmosphere, Theory, Experiments, and Applications, Academic Press, San Diego, 1999.

reduction. In the Los Angeles air basin, for example, the major NOx sources are at the western, upwind end of the air basin. Approximately 40 miles east in the vicinity of Chino, there is a large agricultural areas that has significant emissions of ammonia...under typical meteorological conditions, air is carried inland during the day, with NOx being oxidized to HNO3 as the air mass moves downwind. When it reaches the agricultural area, the HNO3 reacts with gaseous NH3 to form ammonium nitrate..the particles formed by such gas-to-particle conversion processes are in the size range where they scatter light efficiently, giving the appearance of a very hazy or smoggy atmosphere even though other manifestations of smog such as ozone levels may not be highly elevated."

**AMMONIA RELATED $PM_{10}$ FORMATION ENDANGERS BIOTA**

The majority of the ammonia slip reacts with NOx to form ammonium nitrate, which is a form of PM10. This PM10 can be deposited on surrounding hills, located immediately adjacent to the site. This is an especially significant impact, especially if there is already a high level of ammonia compounds emitted in the vicinity of the project. There are many other large ammonia sources in the vicinity of the project, including the Encogen, Tenaska, and March Point projects, and other power plants and large refigeration facilities.

The Federal Land Managers conducts the IMPROVE air monitoring project in the Columbia Gorge area. IMPROVE's results show than almost 40% of fine particulate in the Gorge vicinity is made up of ammonia compounds; ammonium sulfate and ammonium nitrate. These same ammonia compounds could form additional concentrations of PM in the vicinity of the BP plant.

This additional PM10 would increase the Project's reported contribution to soil nitrogen. The impact of this additional ammonium nitrate has not been evaluated and must be to fully evaluate the environmental impacts of SCR. Ammonia emissions are discussed further in the following comments. These types of reactions, as described above, are a potentially significant impact that should have been discussed in the DEIS **1(7)**

**RISKS OF AMMONIA RELEASES**

The plant will store hundreds of thousand of pounds of ammonia on site, and millions of pounds of ammonia will be transported to this site every year. But the DEIS does not describe the likelihood of a transportation accident, the numbers of truck trips bearing ammonia, the possible size of any ammonia releases from a truck accident, the inability of this rural area's emergency response system to react to a large release, the neighborhoods and businesses that would be threatened by a release, or the risk and effects of a release from the ammonia tanks at the power plant, including the risk and effect of a tank failure. **1(8)**

In fact, the DEIS is virtually silent on this troubling subject, of large scale ammonia releases from transport and storage of large amounts of ammonia on the site, and how, or whether, emergency responses will be conducted. Ammonia releases are fairly common. A study submitted to the Congress revealed there have been over 1000 ammonia releases over one nine year period, which

caused 801 injuries, 9 deaths, and 61 evacuations of over 22,000 people. [3]

For instance, there was a release of ammonia in August, 2001 from the Pratt & Whitney power plant in East Hartford, Conn., that caused the shutdown of nearby streets for five hours and led to the evacuation of 20 people. For this reason the commentors urge that the DEIS should have discuss ammonia hazards, and the ability to respond, from storage and transport releases, and any requirements to comply with the CAA amendments governing storage and transport of ammonia and other hazardous materials.

The facility will use anhydrous ammonia which is the most hazardous form of ammonia, and the type of ammonia most often implicated in releases causing injuries, deaths, and evacuations of thousands of people. The DEIS evaluation should have studied alternatives types of ammonia to be stored and used, for instance the use of urea instead of ammonia, or the use of aqueous ammonia, and alternative transport methods for ammonia. Anhydrous ammonia should be specifically banned from use because of the increased dangers from its releases. **1(9)**

The DEIS' evaluation should also study the potential impacts of large scale ammonia releases from different site locations, and the release impacts from different types of transport accidents. **1(10)**

SOME RECENT RELEASES OF AMMONIA (not a complete list)

| evacuations | injuries | location | gallons released |
|---|---|---|---|
| 1000 | 65 | Quebec | " " |
| 1500 | 0 | Morro Bay, CA | 300 |
| 100-300 | n/a | Wauwatosa, Wi | n/a |
| 125 | n/a | Columbus Jct, IA | 200 |
| 36 | 1300 | Minot, ND | about 140,000 |
| 280 | 4 | Washington, IND | Not provided |
| not known | 15 | St. Paul, MN | not provided |
| not known | 9 | Lorain, Ohio | 10 pounds |
| 230 | 5 | Old Monroe, MO | not known |
| 200 | 1 | New Plymouth, NZ | not known |

The Project may be subject to the Title III requirements regarding storage of hazardous materials, but those requirements, including a hazard assessment and risk management program, have not yet been developed and reviewed by the public and the relevant agencies. These requirements should have been fulfilled in time for these proceedings, so that the public can evaluate this project's risks in a single round of reviews and meetings. **1(11)**

---

[3]Report to Congress Section 112(r) (10) Clean Air Act as Amended. EPA 550-r-93-002. December, 1993.

**ALTERNATIVE DESIGNS TO FURTHER REDUCE WATER USE AND DISCHARGE**

The proposed plant will use water cooling. It will consume an average of over 2200 gallons per minute of water; or more than 3 million gallons per day. It will also discharge about 190-260 gpm. (About 300,000 gallons/day)

Over 2200 gallons/minute (Over 3 million gallons per day) is a very high rate of water use for this size of power plant. Many power plants are designed to generate far more energy, while at the same time using far less water than is proposed for this plant. For instance, the proposed natural gas fired Chehalis power generates almost as much energy (520 vs 720 MW) as the BP proposal, but will use only about 7% as much water. The Chehalis plant is solely air cooled.

Many power plants are also able to function without discharging 200 gpm or more of waste water, also, including the Sumas I plant. The DEIS should have more comprehensively discussed alternative designs of the facility that would reduce water use and discharge, as follows. While the DEIS rejected these alternatives as too costly, the widespread use of htese water conservation methods indicates that any increased costs are relatively insignificant. 1(12)

For instance, the BP facility will use far more water to generate 700 MW, than will the Lakefield Junction plant in Minnesota, to generate over 600 MW. Diamond Energy's Nevada plant will use only 20-50 af/year (about 40,000 gallons/day) to generate 500 MW, according to published accounts. Colorado Springs/Fountain will use only 80 gpm to generate 480 MW, compared to BP water use of over 2000 gpm, (well over 3000 af) according to published accounts.

If many other power producers can bear these slightly increased costs, and in the process conserve billions of gallons of water, than the DEIS should conduct a more stringent review of the purported reasons for rejecting water conservation measures out of hand.

**AIR COOLING**

This alternative would include complete air cooling, rather than partial water cooling for the facility. The commentors are aware of many existing and proposed power plants that are solely air cooled, including the two Neil Simpson plants and the Wyodak plant in Wyoming, the permitted Chehalis Power facility in the State of Washington, the Doswell facility in Virginia, the Matimba and Kendal powerhouses in South Africa, the Rosebud plant in Montana, the Linden and Sayreville plants in New Jersey, Colorado Springs near Fountain, Colorado, Diamond Generating, near Goodsprings, Nevada, Duke, and Miriant, both near Las Vegas, Reliant's Choctaw County projects near French Camp, Mississippi, and its Hunterstown, Pennsylvania, project, Taiyuan #2 in China, Trakya in Turkey, Uran III in India, Tousa in Iran, and the Camarillo facility in Ventura County, California.

In addition, most large power plants permitted recently in California have been exclusively air cooled, including Sutter Power, and Otay Mesa. Total Air cooling of the BP plant could reduce water use by 70% or more, and would save about 2 million gallons/day.

**HYBRID COOLING SYSTEMS**
These plant designs use a combination of both air and water cooling, and are in use at the West Cogeneration plant in Germany, and the Exeter Energy plant in Conn., USA. Three Mountain Power is California is another hybrid cooled plant, as is Mass Power's Indian Orchard plant. Water use is cut approximately in half.

**ZERO DISCHARGE PLANTS**
These types of facilities extensively re-treat and re-use their waste water, often with the reverse osmosis membrane process. Public Service in New Mexico has employed this technology for over 20 years, as does the Massena, New York plant, Ocean State in Burrillville, Rhode Island, and FJ Gannon in Florida. There are several variations on this process, including brine concentration. We understand that HPD plant, in Naperville, Illinois, uses this process. Staged cooling, used at Pasco in Dade County, Florida employs this alternative. The nearby Sumas I plant is zero discharge.

The DEIS rejected zero discharge after a truncated discussion that concluded the costs of trucking out waste water solids was too high. The treatment plant for this effluent is going to have solids that will need trucking and disposal, in any event. This was not an adequate discussed of an alternative that would not require the commitment of this massive amount of water for the power plant, and which is in active use at many other competitive power plants. **1(13)**

**WATER QUALITY AND QUANTITY IMPACTS**
The DEIS at 2-27 states that the waste water will have to be concentrated at a ratio of 15-1 before it will be discharged. The water tests in the DEIS did not present an analysis of the trace metals and radioactive materials that may be finally present in the cooling water. Even if these types of materials area present in very small amounts, they will be concentrated by 1500% by the cooling cycles, and this activity could produce a significant concentration of potentially toxic materials in the discharge water. **1(14)**

**WETLANDS**
The DEIS claims that about 30 acres of wetlands will be destroyed by the project, and about 100 acres will be rehabilitated. Again, however, the DEIS fails to inform the reviewers that the degrading of these and directly adjacent wetlands, and the ultimate rehabilitation of other wetlands, is actually the product of two contemperaneous projects; the cogen plant and the isomerization (Isom) unit.

In fact, the Isom unit is currently undergoing its own review by the Army Corps of Engineers, whom admits that the construction lay down area, and the resulting lost wetlands, for the Isom unit (the Brown Road Materials Storage Area)is next to the lay down area, and lost wetlands, for the cogen unit. The wetlands areas proposed for rehabilitation for both the Isom and Cogen units are also contiguous, north of Grandview Road. **1(15)**

But the DEIS fails to discuss the cumulative impacts of the Isom and the Cogen projects on any **1(16)**

resources, including but not limited to wetlands. For instance, the proposed cogen laydown area west of Blaine Road would appear to conflict with the proposed plans for wetlands water conveyance that are part of the Isom project wetlands mitigation plans. 1(16) cont.

**SOME REHABILITATED AREAS ARE EFFLUENT TREATMENT PONDS, NOT WETLANDS**

The DEIS admits that effluent from the cogen's oil-water separator will be discharged to the ponds in CMA-1. The DEIS claims these and other areas provide rehabilitated wetlands which mitigate for the losses of over 30 acres of natural wetlands. But if an industrial uses a ponded area to receive effluent, the recipient area is part of a wastewater treatment plant, not a "wetland."

For this reason, Ecology publications state that "wetlands" created for stormwater treatment are "high risk" because they may receive high sediment and debris loading, or may accumulate toxic materials and become dangerous to wildlife. For this reason much higher replacement ratios are justified. (DOE Publication 92-8, p.14) The DEIS should describe what acreage of rehabilitated areas are being used for receipt of stormwater, so that commentors can determine if an appropriate replacement ratio of wetlands is actually being provided. 1(17)

**DEIS FAILED TO CONSIDER CUMULATIVE IMPACTS WITH THE ISOM CONSTRUCTION AND OTHER RAPIDLY UPCOMING CLEAN FUEL PROJECTS**

The DEIS' failure to discuss the closely related and physically adjacent Isom construction job and its impacts, which will be cumulative with the BP Cogen, violated NEPA and SEPA, which require a study of cumulative impacts of nearby projects taking place at the same time. 1(18)

**PIPELINE IMPACTS**

The proposed power plant and its support facilities include a natural gas pipeline lateral. There are many other natural gas pipelines around the country, and in the Northwest, that were constructed according to federal standards. But in the Northwest alone, pipelines have blown up three times within the last few years.

A pipeline near Bonneville Dam exploded and burned on February 27, 1999. The roar from the explosion was heard for two miles. The 300 foot high fireball was so huge it was visible for miles. Route 14 in Washington was closed to protect the public. Press accounts state that earth movement from recent heavy rains may have been responsible for the pipeline break. The fire destroyed a resort hotel that was under construction and a nearby dwelling.

Near Kalama, Washington, a natural gas pipeline broke in February, 1997. Again, a 300 foot high fireball blazed into the sky. And just one day earlier, the same pipeline exploded and burned near the BP site, Bellingham, Washington.

In March of 1995, that same pipeline had raptured and blew up near Castle Rock, Washington. After that 1995 explosion, the company removed soil from 300 feet of the pipeline, to relieve any

stress. But less than two years later, it blew up again. Again, soil movement was the cause of the pipeline breakage, according to published accounts.

There have been a total of at least ten large natural gas pipeline explosions, since 1978 in the Northwest, including other ruptures in Stevenson, Washington, La Grande, Oregon, and Montpelier, Idaho. All of these explosions have been on the Williams Pipeline system that may supply this proposed power plant.

A few years ago, a construction backhoe caused a leak in a Northwest Natural Gas pipeline recently in Rainier. Seventy five people were evacuated. There is other evidence regarding the potential impact on public health and safety from natural gas pipelines.

Earlier this year, at least six people were killed in a natural gas pipeline explosion near Carlsbad, New Mexico, and another six were injured. Landslides in Ventura county, California ruptured several natural gas pipelines in February, 1998, again after heavy rain. Between 1965 and 1986, there have been 250 pipeline failures in the United States as a result of stress corrosion cracking, caused by a combination of water, soil types, and gas temperature within the pipelines.

Twenty-one people were killed during 1995 from natural gas pipeline accidents.[4] A Transwestern Pipeline natural gas pipeline exploded on August 20, 1994 in New Mexico, near the Rio Grande River, damaging a bridge. An October, 1994 explosion of a pipeline in Torrance, California, injured 30. A December, 1989 pipeline rupture caused by a farmer's plow, triggered the evacuation of 600 people in Butler, Illinois.

In March, 1994, a natural gas pipeline exploded in New Jersey, killing and injuring scores of people and creating a 30 foot deep crater and a fire that destroyed eight buildings and severely damaged six more buildings.

All of these pipelines were constructed to federal standards, and monitored by federal agencies. The DEIS should explain, how with all the mitigation measures and careful engineering, pipelines, including facilities in Washington State, on the very pipeline that will service this power plant, can still blow up. When these events occurred in a populated areas, there may be heavy loss of life and property. These pipeline explosions are significant impacts. Additional protective measures should be discussed and implemented, and the problems that caused this explosion should be carefully explained at length in an revised DEIS. **1(19)**

But the DEIS did not discuss pipeline accidents, also known as "service incidents."
A service incident is reportable if there is a gas leak causing a death or serious injury, gas ignition, over $5000 in property damage, if it occurred during a test, if it required immediate repair, or if a portion of the line was taken out of service because of the incident.

---

[4] New York Times, 4/9/97, p. 1.

An revised DEIS should be prepared to describe the likely scenario of service incidents on the pipeline serving the power plant, perhaps by describing several of the recent explosions on this pipeline and at similar pipelines. 1(20)

Descriptions of a range of several recent incidents should be provided, so that readers and commentors can be appraised of the possible impacts of service incidents. This is appropriate because service incidents can be expected over a 50 year life span for these pipelines. The DEIS should also have discussed whether, and how local agencies in this area would respond to a pipeline explosion and fire. 1(21)

**POWER PLANT ACCIDENTS**

The DEIS failed to discuss the potential for accidents and explosions at this proposed facility. On occasion, similar power plants have experienced fires and explosions that have damaged property and killed people.

On October 8th, 2002, a massive explosion at the Florida Power & Light natural gas fired Palm Beach plant rocked two counties, followed by a hydrogen-fed fire. The explosion shook houses and rattled windows, and was as loud as a sonic boom. In January, 2002, there was a hydrogen explosion and a resulting fire at the natural gas fired BC Hydro plant in Port Moody, BC.

Less than two weeks ago, on October 1, 2002, there was a nine-alarm fire at the Sithe power plant in Boston, that began in a hydrogen generator. The fire and explosion caused $10 million in property damage.

The BP DEIS does not apparently even mention the use of hydrogen at that plant, or list it as being stored on site. We understand that hydrogen is routinely used and stored at natural gas fired and other power plants similar to BP, including but not limited to these three plants, that have blown up recently. But this potential impact from explosives and fires from caused or fed by hydrogen, and the impact on emergency services to respond, was not adequately discussed in the DEIS. 1(22)

At the Sithe blaze, 180 firefighters had to respond. The natural gas fired turbine at the Doswell power plant in Virginia recently suffered an catastrophic fire and explosion. It took 75 fire fighters to quell the resulting fire The DEIS should have discussed what will happen if hundreds of fire fighters are needed to respond to a problem at BP.

There were other explosions and fires at power plants recently. An explosion and fire rocked the Black Hills Power and Light power plant in Wyoming, in June, 2002. A back-up generator blew up and caused a "major" fire at the Allegheny Energy plant in Pennsylvania, in July, 2002. Firefighters from at least five communities had to respond to the blaze. A pressure relief valve activation at the Mirant plan in Zeeland, Michigan in August, 2002 caused diversion of traffic, to avoid released gasses.. Three workers were killed at a fire in the O'Brien Newark, New Jersey Cogeneration power plant fire recently. At least 20 other fires have been recorded over the last

10 years at power plants, causing another death and $417 million in property damage. The most severe fires often involved the release of lube oil, which ignited. Thousands of gallons of lube oil will be stored at BP.[5]

There were 272 to 557 equipment failures and accidents per year at power boilers and pressure vessels since 1992, causing almost 200 injuries and 29 deaths, and another 145 to 387 failures, and another 270 injuries and 54 deaths, from unfired pressure vessels, according to Power Magazine, Jan-Feb., 2001, p 53.

Because Power plants typically store and use many materials that present a danger of fire and explosion, such as hydrogen and lube oil, some of these hundreds of annual accidents at power plants cause injuries, and losses of life and property beyond the power plant boundaries, and require a large response of emergency personnel, as previously described. The dangers from the use and storage of these materials, and even the types of materials to be stored at BP, and the ability or lack thereof of local fire departments to respond, was not discussed in the DEIS. These kinds of serious accidents are significant impacts that should be discussed in an EIS. 1(23)

**CUMULATIVE EFFECTS OF INCREASED USAGE OF NATURAL GAS**

The EIS did not discuss the adverse impacts from the increased exploration and processing of gas in Canada, in part sparked by the development of these this project.

Discussions of Canadian impacts is mandated by Presidential findings during the Carter Administration regarding the scope of NEPA-covered projects. A description of Cross-border impacts are also appropriate, considering that the Canada Energy Board requires assessments of impacts in the United States, when evaluating proposals for Canadian pipelines. 1(24)

Nor did the DEIS adequately discuss the cumulative impacts of this project and the many other power projects in the Northwest, on the natural gas supplies. Although this very topic was the subject of a chapter in the Wallula Power EIS, it received inadequate discussion in this document, even though the cumulative impact of some of the recently proposed power plants in the Northwest, was the additional consumption of over 6% of domestic natural gas reserves.

**PM-10**

**ADDITIONAL PM SOURCES**

. The DEIS also lacks adequate information to assure commentors that its calculations included the impact from formation of secondary PM by conversion of ammonia. While the DEIS did discuss secondary formation of PM from conversion of nitrogen and sulfur compounds, the DEIS did not discuss secondary formation of PM by conversion from airborne ammonia compounds. 1(25)

This plant will emit hundreds of tons per year (TPY) of PM-10 from its turbines alone PM-10 is fine particulate that is capable of being drawn deep into the lungs. PM-10 is highly damaging to

[5]Most of these narratives are from the Chemical Safety Board's web site.

human health. But in addition to the power plant exhaust, there are other sources of PM-10 and total suspended particulate (TSP) from this project, including the cooling tower.

**COOLING TOWER DRIFT**

The cooling towers are PM-10 and TSP sources, to the degree which the cooling water contain solids, which are emitted from the cooling tower exhaust as particulate. A large power plant using water high in solids content can emit many tons per year of PM-10 and TSP. For instance the Goldendale Energy plant was predicted to emit 6.6 TPY of PM, and BP is 300% larger. The PM emissions from the cooling tower will contribute significantly to the ambient air concentrations of $PM_{10}$ concentrations. The effluents have low exit temperatures, low exit velocities and correspondingly are low in momentum and buoyancy. Switching to full air cooling would also reduce PM and TSP emissions, since a cooling tower will no longer be needed. 1(26)

Cooling tower emissions also contain salts, metals, water treatment chemicals, and other contaminants, which could degrade the quality of soils, and affect human health, wherever the cooling tower drift is deposited. .

**THE DEIS FAILED TO CONSIDER HOW AMMONIA SLIP WILL ADD TO PM10 EMISSIONS**

The DEIS failed to describe the reactions between SO3, NH3, and NO2, which form salts, some of which are emitted to the atmosphere and some of which deposit within the HRSG. Equations can be used to estimate a portion of the secondary $PM_{10}$ that is formed from ammonia slip. Secondary $PM_{10}$ can be formed by reaction of ammonia with $SO_3$ and $NO_2$ emitted by the gas turbines and present in the stack gases and plume as well as additional $SO_3$ and $NO_2$ that are present downwind in the atmosphere.

Additional ammonium nitrate could form from the reaction of $NO_2$ in the atmosphere with any emitted ammonia. This additional $PM_{10}$ may not have been included in the Project's emissions estimates. Apparently the formation of secondary PM10, ammonia nitrate, from the proposed project, was not done in the DEIS, so the combined PM10 emissions will be more than what was estimated. BPA's own EIS on the Wallula Power project admitted ammonia emissions could produce as much as 460% of their own weight as secondary particulate.

1(27)

In summary, the DEIS appears to have underestimated the resulting concentrations of PM 10 from the project. These underestimations need to be considered in light of the Federal Land Managers certifications that significance degradation of air quality in nearby Class I areas are already being exceeded. This certification by federal agencies of an already occurring significant impact, that will be increased by the proposed project, was not mentioned in the DEIS

For these reasons, the subject of the health and environmental effects of PM-10 and the plant's contribution individually and cumulatively, should have been presented in depth. Many recently published studies demonstrate that PM-10 and TSP are far more harmful that previously considered. In one study of the Seattle area, days of high particulate concentrations in the air

were correlated with increased hospital visits for asthma. In another series of similar studies, days of high particulate concentrations were correlated with days of high death rates in Santa Clara, California, Steubenville, Ohio, Birmingham, Alabama, and Philadelphia, Pennsylvania, among seven separate studies on this topic. Particulate have been recently, convincingly implicated in harm to pulmonary function.

Some important conclusions from these studies is that harmful health effects occur even when particulate concentrations are far, far below the legal limits, there is no apparent particulate threshold for adverse health effects, and that harmful health effects are apparently caused by very minor increase in particulate concentrations. This means that even though the Project will not cause violations of the PM legal limits it could still cause significant health impacts. Construction will also create about 1 ton of TSP per acre of disturbance per month. Construction equipment, truck and car traffic related to this project, both in the construction and operation stage, will be an additional PM-10 and TSP source.

It appears from these studies that <u>any</u> increase in PM-10 and TSP levels will cause an adverse health impact. This is a significant health impact that should have been discussed in an EIS. There are important environmental impacts from PM-10 emissions, also.

**IMPACTS FROM WATER DISCHARGES**

The DEIS does not list water treatment chemicals to be used at the plant, and does not list any details of the toxicity of inhibitors or algicides that would be discharged. Lacking a complete discussion of the possibly pollutants in these sources's discharge, it is not possible to conclude that the this source's waste water will not contribute to water treatment problems. These chemicals could also be discharged in the cooling tower discharges. **1(28)**

**SOLID WASTES**

Water treatment for a large power plant can generate as much as 10 tons per month of wastes, as backwash, or filter cake. There are other waste streams, including spent catalyst, which is a hazardous waste. Catalyst wastes could be avoided by used of the SCONOX scrubber system. This generation of wastes was never described adequately in the DEIS. The materials contained in this wastes, the amount to be produced, its destiny, and its impacts on landfill capacity should all have been discussed. **1(29)**

**STORMWATER RUNOFF AND SPILLS**

The project will include the creation of impervious surfaces. This will cause the generation of millions of gallons of storm water runoff. This water will be tainted with oil, grease, and other contaminants present on the site and its parking lot and roof. The DEIS did not describe adequately the quality of this runoff, its destiny, and its potential impacts on nearby wetlands and surface waters. While there would be unlined detention ponds the DEIS did not describe to what degree these ponds will treat the storm water to remove pollutants before it is allowed to infiltrate into the ground water. **1(30)**

While an oil/water separator will be present, the DEIS did not assure commentors about the degree to which stormwater will be channelized through the separator. Nor did the DEIS describe the fate of wastes that are separated from the storm water. The DEIS did not describe the project's compliance with the DOE Stormwater Management rules. For instance, use of oil/water separators is actually criticized as having limited application, in DOE guidance manuals. The DEIS did not describe why a separator was appropriate for this location, or why alternative methods of storm water pollution control were not used. [6] 1(31)

**LEGIONNAIRES DISEASE**

The DEIS did not provide a table of materials stored on site that listed biocides known to be effective against Legionnaires Disease. This disease breeds in moist, warm climates, including cooling towers such as those to be used by BP. It has been spread through the discharge of steam from cooling towers. In March, 2001, for instance, two Ford employees died in Ohio after exposure to Legionnaires' Disease, spread by the facility's industrial cooling towers. Legionnaires Disease organisms have also bee found in the CEGB power plant's cooling tower water, near Stafford, England. Since it is not apparent that BP plans to use appropriate chemical treatment of its cooling tower system to stifle development of the relevant bacteria, there is a threat of Legionnaires Disease from this facility. This should be discussed in a revised DEIS. 1(32)

**POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)**

The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure. EMF exposure is another potentially significant impact that was not discussed in the DEIS.

**POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)**

This project will include a new power line. The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure, and the impacts to avian species which collide with above ground power lines.. Bird Mortality from the new power lines and EMF exposure are other potentially significant impacts that should have been discussed in the DEIS, and power line burial should be discussed as a mitigating factor, and a method of avoiding impacts on the nearby sensitive areas. 1(33)

The power lines associated with this project, as currently proposed, are a potentially significant factor. The DEIS should have addressed to what degree power line burial would address this concern,.

There are many examples of burial of high voltage power lines of considerable length. Since the proposed lines are about 3000 feet long, burial of this line would reduce the visual impact of the project would protect avian species, would reduce the project's above ground "footprint," and

[6]Department of Ecology. Stormwater Management Manual. Chapter III-7. #91-75.

would add only about 1/10% of one percent to the project costs; about $500,000.

Some example of actual and proposed burials of large pipeline include the 345 kV line that would be buried for 1700 feet to go under the Namekagon River near Trego, Wisconsin.

Sierra Pacific is burying a 14,000 volt line for about 2000 feet near downtown (Lake) Tahoe City, according to the company's June 9, 1999 press release.

Sierra Pacific is also burying a 120,000 volt (120kV) line for about 1700 feet near Carson City, Nevada, according to the company's April 19, 1999 press release.

Sierra Pacific's longest underground line is 2.6 miles, according to their Media Relations department.

The California Public Utility Commission's consultants, Aspen Environmental, prepared a study of an all-underground route for a 230 kV line near Pleasanton, California (Pleasanton Weekly. "Objectors, Proponents speak out on PG&E Power Line Plan." 2/16/01) **1(33) cont.**

The Sumas II Power Plant has proposed a buried 230 kV line for 1.4 miles, in Abbotsford, Canada, as part of its trans-border proposal. (Canada Newswire. "NSB Receives a Revised DEIS from Sumas Energy II to Construct an International Power Line." October 2000)

The Sargent & Lundy engineering firm's advertising materials list several underground transmission lines for which they provided engineering, including a 115/138-kV line, a 230 kV line in Washington Dc, a 1800 foot 115-kV line in Baltimore, five 230-kV lines in China, two 69 kV lines in Iowa, a 1300 foot 138-kV line in Tennessee, and a one-mile, 138-kV line in Salt Lake City.

This litany of buried transmission lines indicates that this is a practicable, feasible and economic alternative design for this portion of the project. It would reduce the visual and land use impact of the project. For this reason a burial alternative, should have been presented in the DEIS.

**QUESTIONS ABOUT THE EMISSIONS OFFSETS**

The power plant will be permitted to emit the following annual tonnages.

NOx 239
CO 158
VOC 41
PM10 251
SO2 51

BP will purportedly shut down existing boilers, creating the following offsets:

NOx 499
CO 54

VOC 28
PM 94
SO2 7

The DEIS claimed this would have the following net impacts
NOx -249
CO 104
VOC 13
PM 156
SO2 43

This list does not include the increased NH3 emissions of another 346 TPY. While the NH3 emissions are not a criteria pollution, it is still a toxic air emission, and an important source of secondary particulate matter, which is a criteria pollutant. Indeed, there is some evidence that BP's new power plant NH3 emissions will be responsible for an increase of as much as 1400 TPY of secondary PM. 1(34)

**DEIS DID NOT INCLUDE THE EMISSIONS INCREASES FROM THE CONTEMPORANEOUS ISOMERIZATION PROJECT**

This data also does not include the contemporaneous isomerization project at BP. The isomerization project will be constructed at the same time as the Cogen project, it will share the same construction lay-down yard, and in fact will share the same wetlands mitigation plan with the Cogen. The isomerization project will cause the following increases in air pollution, according to an on-line description of the project by EPA Region 10: 1(35)

| POLLUTANT | TONS/YR | DEIS CLAIMED CHANGES | NET INCREASE W/ ISOM |
|---|---|---|---|
| NOX | 166 | -249 | -76 |
| PM | 11 | 156 | 167 |
| SO2 | 84 | 43 | 127 |
| VOC | 31 | 13 | 44 |
| CO | 47 | 31 | 78 |
| H2SO4 | 2 | | 38* |
| NH3 | | | 173* |

*Includes totals from Table 3.2-13

**DEIS DID NOT ADEQUATELY DISCLOSE INFORMATION ABOUT THE PURPORTED EMISSIONS REDUCTIONS FROM THE SHUTDOWN OF THE REFINERY BOILERS**

ERCs must be surplus, permanent, and verifiable. The boilers that will be shut down are old, and may be shut down after the Clean Fuels project provides new boilers, so these sources would permanently emit at the levels which the DEIS claims as credits. RACT (Reasonable Available Control Technology) of BACT determinations should be made to determine realistic Emission

offsets credits. Another indication that the emissions credits are not permanent is the requirement of the BP Consent Decree which mandates NOx reductions at the Cherry Point refinery. These sources may not be permitted to function at the current levels, anyway.

The DEIS also admits that new boilers will be constructed during the upcoming Clean Fuels Project. (p. 3.2-28) For this reason, the DEIS inappropriately deducted the old boilers' emissions from new cogen emissions during its discussion of the net project impacts. In other words, the old boilers' emissions are going away very soon, cogen or no cogen. The DEIS needed to discuss the emissions from the new Clean Fuel boilers, as the only proper, legitimate offsetting emissions reductions that could be deducted from the new Cogen emissions. Since the DEIS failed to consider the permitted emissions from the boilers that are about to be constructed, the DEIS's claims of new air quality benefits are misleading and untrue.

Emission reduction credit guidance from the EPA (cited later in this document) generally suggests that the low value of actual emissions, vs. permitted emissions should be employed to determine the appropriate ERC. But the DEIS does not say if the figures given for the boiler emissions were permitted or actual emissions.

**DEIS DID NOT DISCUSS THE NOX REDUCTIONS MANDATED UNDER THE BP CONSENT DECREE**

Furthermore, BP is under the strictures of a Consent Decree with the Federal EPA, under which BP is required to reduce its NOx emissions at the majority of its heaters and other equipment at the Cherry Point Refinery. The Consent Decree also set limits on how BP can characterize NOx emissions reductions from equipment subject to the Consent Decree. The DEIS did not discuss the relationship between the NOx reductions required under the consent decree, and the NOx reductions from shutdown of the utility boilers, that is discussed in the DEIS. **1(36)**

This discussion should be required in the DEIS because ERCs must be surplus, quantifiable and permanent. If the old boilers were not shut down, it is doubtful that the old boiler emissions would have continued permanently at their current rate, because at some point RACT would have been mandated. Thus the boilers' emissions above RACT levels are not surplus, because some reductions will soon be required by law.

Permanent ERCs should not be based on past, high, emission rates, since those rates will not continue indefinitely, due to imposition of RACT, and the requirements of the Consent Decree, among other factors.

Federal register discussions state that VOC sources can be considered to impact ozone non-attainment areas within 36 hours wind travel time, because precursor emissions that occur within 36 hours traveltime of each other interact to form oxidant.[1]

Based on these discussions, The commentors ask that the old boilers at BP can be considered to contribute to the recent non-attainment status of the Seattle and Vancouver BC

areas. EPA policy discussions suggest that RACT emission rates should be considered, rather than actual emission rates, or whichever is lower, for sources that are in non-attainment areas.[2] 1(36) cont.

The commentors are also concerned that several other criteria be followed in determining an acceptable amount of ERCs from the old boiler shutdown. The DEIS should establish that the Washington SIP does not already include, as part of its attainment plans, emissions reductions from shutdowns and the phasing out of aged emission units.

Some SIPs assume a quantity of reductions from new plant openings and existing plant shutdowns. These SIPs incorporate into their attainment strategy a net "turnover" reduction in emissions because new plants will be cleaner than the old shutdown plants.

If the Washington SIP includes this sort of "turnover" emissions reduction as part of an implementation strategy, then ERCs from the shutdown of the old BP boilers should not be granted, otherwise those emissions reductions would be double counted. (Federal Register 4/7/82, p. 15081)

In addition, if the Washington SIP contains emissions limits for the BP old boilers that are lower than BP's computation of its ERCs, then the SIP limits should be used to compute ERCs instead. (Federal Register, 1/16/79, p. 3284)

In summary, the old boiler actual emission rates should be compared with RACT/BACT emission rates from similar units, and the lower of those two rates should be used in the DEIS discussion of emissions reductions from the old boilers' shutdown.

**AIR TOXICS**

The new cogen project will emit several highly hazardous air toxics, including benzene and formaldehyde, and others, which are listed at Table 3.2-13. Toxics such as Acrolien, (and several metals), are emitted at amounts exceeding the Small Quantity Emissions Rate for both the hourly and annual emissions rate. But the DEIS fails to describe whether the project will result in greater or lesser emissions of these and other air toxics. The DEIS does not compare the emissions of air toxics from the cogen project, with the purported "reductions" caused by the shut down of the older utility boilers. 1(37)

The DEIS should have performed this comparison. It is not wise or legal to trade increases in comparatively hazardous air pollutants for decreases in relatively less harmful pollutants. Such a trade should be fully disclosed and discussed on an DEIS. As one treatise on this topic stated:

> "Certainly no one should be allowed to trade an increase in a more harmful pollutant for a decrease in a more benign one simply because it is cheaper to do so...if an increase in a hazardous pollutant were to be traded for a decrease in a more benign one the net effect would be a greater threat to public health despite the equivalence in pollutant quantities." [3]

But the trade-off of some decreases in NOx emissions from the old boilers, for increased emissions in formaldehyde and benzene emissions and other VOCs and air toxics from the BP Cogen, is a trade of comparatively benign pollutants for more harmful pollutants. In particular, benzene increases as a trade for reduction of generic emissions are explicitly prohibited.

EPA guidance documents regarding pollution trades and reductions clearly and plainly state:

> "(E)ven within a category (such as VOCs), pollutants that pose significant health hazards cannot be traded against less harmful pollutants ... The emissions of ...benzene which (is) listed under section 112, may be increased at one emission point ... only as long as there is a compensating decrease in the emission of the same pollutants at another emission point at the same location or a contiguous location ... Sources may equally trade hazardous pollutants with nonhazardous pollutants in the same criteria pollutant category only in the cases where the source decreases the emission of the hazardous pollutant.(emphasis and parentheses comment added) [4]

A later update of this guidance document continued to maintain the ban on trades of hazardous for non-hazardous pollutants, and specifically proscribed trades involving increases in benzene emissions:

> "Emissions Trades Should Not Increase Hazardous Pollutants. Where pollutants have been listed under Section 112, but are not yet subject to specific regulations...states may allow trades consisting of equivalent increases and decreases of the same listed pollutant ... the State may also approve trades in which reductions of hazardous pollutants compensate for increases in non-hazardous pollutants....a source may trade benzene for any non-hazardous VOC, if the benzene emissions are decreased." [5]

This coverage of this quotation would also apply both to formaldehyde, which was listed under Section 112 as part of the Clean Air act amendments of 1990, and to benzene, which was listed at an earlier time under Section 112. Language in the amended Section 112 also addresses trades of hazardous pollutants as follows;

> "A physical change in ... a major source which results in a greater than de minimis increase in actual emissions of a hazardous air pollutant ... will be offset by an equal or greater decrease in ... emissions of another hazardous air pollutant ... which is deemed more hazardous." [6]

**CONCLUSIONS**

ERCs from the old boilers shutdown should be limited to the RACT emissions from these boilers, or the actual boiler emissions, or the emissions of the Clean Fuel Project replacement boiler, whichever is lower. If these boilers are supposed to be shut down or controlled under the Consent Decree, those reductions should not be considered credits at all. Reductions in non-

toxic air emissions should not be described as offsetting increased emissions of air toxics. If air toxic emissions will actually rise, the DEIS should say so and provide details.

## ENDNOTES

1.Federal Register, Vol. 44, No. 11, January 16, 1969. P. 3278- 9.

2. Federal Register, 4/7/82, p. 15080.

3. Landau, Jack. "Economic Dream or Environmental Nightmare? The Legality of the "Bubble Concept" in Air and Water Pollution Control." Environmental Affairs. Vol. 8:705, pp. 770 and 780.)

4. Federal Register Vol. 44, No. 239, December 11, 1979, page 71784.

5. Federal Register, Vol. 47, No. 67, April 7, 1982, pp. 15082-3.

6.Public Law 101-548, Nov. 15, 1990, 104 Stat.2544.,Section 112, (g)(1)(A).

John Paul Williams
Industrial researcher
19815 NW Nestucca Dr
Portland OR 97229
503-439-9028
fax-503-533-4082
john.williams3@attbi.com

**QUALIFICATIONS**

I have been involved in the permitting and reviews of federal and state environmental impact statements, environmental reviews, and permitting and reviews of air permit applications of industrial facilities, including cogeneration facilities, power plants, and a variety of industrial facilities, for sixteen years, throughout the West and Northwest. I have a BA degree in history from the University of California at Berkeley, and I am a member of the Northwest Chapter of the Air and Waste Management Association.

Over the last 16 years, on behalf of law firms, environmental and public interest groups, companies, and individuals, I have reviewed many environmental assessments for a variety of industrial facilities, including power plants, throughout the Midwest and West.

My recent participation on behalf of private parties in review of the Chehalis Power natural gas fired facility helped lead to a 70%, or 520 ton/year reduction, in that power plant's permitted nitrogen oxides emissions. My participation also caused the developer to switch to a more-efficient water conservation measure, thus reducing its water use by about 2 million gallons per day.

My participation in the air permit review of the Amax Hayden Hill Gold Mine in California was a factor in an enforcement action and consent decree by the Federal EPA, and a resulting fine in the $300,000 range, and additional air quality mitigation provided to local agencies. My assistance in preparing a critique of the Sierra Pacific Aberdeen, Washington air permit application led to a stop work order and a $10,000 fine against Sierra Pacific, in August, 2002.

When I was a paralegal for the Adams & Broadwell law firm in Northern California in the late 1980s, I participated in the review of scores of environmental reviews of power plants, refineries, and other types of industrial facilities throughout California. I participated in the review of the air permit for one of the largest wood fired power plants in the country in the late 1980s, what was then the Signal Energy facility near Redding, California. This was the first-ever installation of an added-on pollution control system, that of Selective Non-Catalytic Reduction (SNCR), onto a wood fired power plant.

I have attached a partial list of recent environmental assessment and permit reviews in which I have participated on behalf of a variety of private clients and environmental groups.



Exhibit 2

POWER PLANTS
Cogentrix power plant, Oregon
Cogentrix power plant, Rathdrum, Idaho
Kootenai Power, Idaho
Avista power plant, Longview, Washington
Sumas II power plant, Washington
Chehalis Power, Washington
Goldendale Power, Washington
Tenaska I power plant, Whatcom County, Washington
Tenaska II power plant, Tacoma, Wash.
Sierra Pacific cogeneration power plant, Greys Harbor, Wash.
Mission Energy/Weyerhaeuser power plant, Longview
Tollhouse power plant, Sedro Wolley, Wash.
power turbine, Willamette Industries, Albany, Ore.

**INDUSTRIAL FACILITIES**
Cascade Grain ethanol plant, Oregon
Morton Chemical, Elma Washington
PGT Pipeline expansion, Washington, Idaho, Oregon
Olympic Pipeline, Washington
Tuscarora Pipeline, Oregon, California, Nevada
Skagit and Nooksack River Basin Hydroelectric plants, Washington
Weyerhaeuser pulp mill expansion, Longview, Washington
James River Paper, Wauna, Oregon
General Chemical, Washington
Frito-Lay, Washington
Steel Dynamics Mill, Whitley County, Indiana

**GRAVEL AND SAND MINES, CALIFORNIA**
Western Aggregates, Marysville, California
Gilt Edge Tract, Yuba County, Ca.
Calaveras Materials, Fresno, California
Silica Resources, Marysville, California
Kaweah River Rock, Tulare County
Desert Aggregates, Tulare County
Garcia Gravel, Timbuctoo
Bud Plant, Yuba Goldfields
River City Aggregates, Sacramento County
Granite Rock, Santa Cruz County
Vulcan, Sacramento
Terra Blanca, Tulare
County Quarry, Hollister, Ca.

**GOLD AND COPPER MINES**
**CALIFORNIA**
AMAX Hayden Hill Mine, Lassen County, California
Homestake Mine, Lake County
Cal-Sierra, Yuba Goldfields
Mesquite Mine, Imperial County
Kinross, Timbuctoo, Ca

**NEVADA AND UTAH**
Denton-Rawhide, Nevada
Homestake Gold Mine, Nevada
Kennecott, Salt Lake City
Cortez, Nevada
Jerritt Canyon, Nv
Lone Tree, Nv
Twin Creeks Nv
Mule Canyon, Nv
Florida Canyon, Nv
Magma, Nv.

**RECENT PUBLICATIONS**
"Thirsty Power Plants a Threat to Local Water." Cascadia Times. October, 2001.
"New Power Plants Threaten Northwest Environment," Portland Oregonian, Nov. 27, 2001