Small Business Economic Impact Analysis

Chapter 173-407 WAC
Carbon dioxide mitigation program for fossil-fueled thermal electric generating facilities

Chapter 173-218 WAC
Underground injection control program

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You can also view this report on the Department of Ecology's Web Site at
http://www.ecy.wa.gov/biblio/0802006.html

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Note: Due to size limitations relating to the filing of documents with the Code Reviser, the SBEIS does not contain the appendices that further explain Ecology's analysis. Additionally, it does not contain the raw data used in this analysis, or all of Ecology's analysis of this data. However, this information is being placed in the rule-making file, and is available upon request.

Executive Summary

This analysis finds that there are disproportionate impacts from the proposed rule. Cost minimization is listed. Four jobs are lost.

All new power plants permitted for operation in Washington after June 2008 will need to demonstrate that they comply with the proposed rules. Ecology anticipates that new natural gas combined cycle turbine facilities will be able to comply easily. Coal, oil, and gas boiler facilities will find it difficult to comply without geological sequestration.

Given the existing economic environment and the cost of capturing carbon for sequestration, Ecology assumes companies will choose to maximize their use of the flexibility in the law and in the proposed rules. This makes it less likely that the proposed rules will cause any existing or hypothetical new power plants to capture and sequester carbon dioxide ($CO_{2)}$. Rather they will be more likely to switch fuel.

1. Background

The Washington State Department of Ecology (Ecology) is proposing to amend:

- Chapter 173-407 WAC Carbon dioxide mitigation program for fossil-fueled thermal electric generating facilities
- Chapter 173-218 WAC Underground injection control program

In 2007, state lawmakers passed new climate change legislation that Governor Christine Gregoire signed into law on May 3, 2007. The new law (Chapter 80.80 RCW) requires Ecology, in coordination with the Energy Facility Site Evaluation Council (EFSEC), to adopt rules setting a greenhouse gases emissions performance standard. The rules will set standards for:

- Baseload generation and cogeneration facilities[1] in Washington.
- Baseload[2] electric generation for which electric utilities enter into long-term financial commitments[3] on or after July 1, 2008.

Reason for this rule proposal

Carbon dioxide (CO_2) is the main source of the greenhouse gas emissions that are contributing to climate change. Electricity generation is the third leading contributor of greenhouse gases in Washington, behind transportation and the direct use of fuel. Ecology is proposing rule amendments that will:

[1] A cogeneration facility is a fossil-fueled thermal power plant in which the heat or steam is also used for industrial or commercial heating or cooling purposes and that meets federal energy regulatory commission standards for qualifying facilities under the public utility regulatory policies act of 1978.
[2] Baseload electric generation (Ch. 80.80 RCW) means electric generation from a power plant that is designed and intended to provide electricity at an annualized capacity factor of at least sixty percent.
[3] Long-term financial commitments (Ch. RCW 80.80) means a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility or b) A new or renewed contract for baseload electric generation with a term of 5 or more years for the provision of retail power or wholesale power to end-use customers in this state.

- Implement a CO_2 emission performance standard of 1,100 pounds of greenhouse gases per Mega Watt hour (MWh) of power generated for baseload power plants.
- Establish an output-based methodology for calculating greenhouse gas emissions from a cogeneration facility.
- Establish performance standards to protect the quality of ground water associated with a carbon capture and sequestration project.
- Establish criteria for evaluating carbon capture and sequestration plans submitted by power plants.

All of these are necessary to implement the new law and they will help us begin to address the impacts of climate change in Washington and support the Governor's Climate Change Challenge Executive Order (07-02).

Scope of Analysis

Although the energy sector has broad impacts, Ecology has defined a narrow scope for this analysis.

- This analysis does not deal with energy and economy interactions. It only addresses change to the electrical sector for electricity sold to the grid.
- Generally, this kind of analysis only covers the costs of the proposed rule.
- The price data in this document are from the market and include the impacts of all existing subsidies. Most energy sources are subsidized. Hydro, wind, solar, and fossil fuels all receive different forms of subsidies. Ecology has not attempted to net out the price effect of subsidies from the cited data because the market interactions are too complex to allow it.[4] The USDOE estimates do not appear to include subsidies, except that the modeled price of coal and natural gas come from a market that is affected by subsidies. The price data used to determine the viability of carbon capture in this document are from the market and therefore include the impacts of all subsidies.

Comparison of the Current and Proposed Rules

Two rules are affected by this proposal. This analysis covers both rules. The first rule is WAC 173-407, implementing the requirements of RCW 80.70. The second rule is WAC 173-218, implementing provisions of RCW 90.48 to protect groundwater quality.

Current rule requirements

The existing rules of WAC 173-407 implements the provisions of RCW 80.70 that do not affect the activities or permitting requirements of Energy Facility Site Evaluation Council (EFSEC). The existing rule requires ***mitigation*** "of the emissions of CO_2 from all new and

[4] The energy sector affects and is affected by every sector of the economy. The subsidy with the most direct impact on fossil fuels is the depletion allowance. However indirect effects taken together may swamp the more direct effects of this subsidy. A couple of examples will suffice to illustrate the complexity. The ability of homeowners to write off interest on home loans when paying income tax may mean larger homes and more demand for electricity. Property taxes may mean smaller homes. Subsides for roads from municipalities may create more demand for gasoline, which in turn means a smaller share of fossil fuel goes into heating oil, which increases demand for electricity. Other things operate in the opposite direction. Even general equilibrium models have trouble handling all these interactions. Ecology has therefore not attempted to sort them out.

certain modified fossil-fueled thermal electric generating facilities with station-generating capability of more than 25 MWe.[5]" The law and existing rule require that the mitigation cover the expected emissions for the 30 year expected lifetime of a power plant. Carbon capture and sequestration is one option for accomplishing this.

The existing rules of WAC 173-218 WAC do not include specific requirements for using underground injection control wells for underground geologic sequestration of carbon dioxide, but they do regulate the discharge of fluids into the wells to prevent ground water contamination. Permits for these types of projects are required under RCW 90.48 RCW, Water Pollution Control and WAC 173-216, the State Waste Discharge Permit Program.

Description of proposed changes

Who is affected?

The rule applies in a complex manner and would apply to power plants only in specific cases. This is laid out in Table 1. Any plant that meets the criteria in the table must comply, however it will be easier for the new natural gas turbines and gas/oil turbines to meet the requirements. Given the 1,100 pounds of CO_2 per MWh emission performance standard, the law and the proposed rule are most likely to affect coal-based power plants. Affected coal power and old style natural gas boilers are likely to need carbon capture and sequestration to comply. Based on recent project permitting history, only natural gas combined cycle power plants are likely to be proposed and permitted for baseload operation in Washington. However, the law and the rule have flexibility which limits who is affected.

Baseload generation

According to the definition of baseload generation in WAC 173-407-110 if a new generator finds it is viable to operate *less than* 60 percent of the time so that they are not part of baseload generation, then the proposed rules would not affect them. This means a new generator could purposely build a facility to be permitted for operating at only 60 percent to avoid having to meet the requirements of the proposed rules. This is true even if the facility provided power on an emergency basis for *more than* 60 percent of the year.

The other side of this scenario is that the law and proposed rules are likely to limit the development of any new large coal or inefficient fossil fuel power plants. This is because these types of power plants must operate more than 60 percent of the time to make a profit

For plants outside Washington, selling power into Washington, the law and rule limit emissions from baseload facilities that are subject to contracts for more than five years and they cannot put power on the system as an unspecified source.

Short-term contracts

Because the law only covers long-term contracts the proposed rule (WAC 173-407-300, 310 and 320) can only addresses long-term contracts. Therefore, short-term contracts for purchases of less than five years are not covered. This means entities

[5] WAC 173-407-010(1)

who want to buy electricity from a new coal or another fossil fuel source (that is not required to comply with the new law or proposed rules) will be able to do so, but only based on short-term contracts. This creates some uncertainty for any new coal or other fossil fuel generators who prefer long-term contracts to guarantee payoff of construction loans. This uncertainty may limit their willingness to develop this resource in Washington.

Distributed Generation

Distributed generation is when power is generated but no power is sold to the grid it is used to supply only the electrical needs of the facility for where it is located. This is not cogeneration. Even if these types of generators end up providing power during peak or emergency times, via short-term contracts, they would be unaffected by the proposed rules.

Emergency Generation

Emergency generators are designed to come on if grid power is lost. These generators will be unaffected.

Averaging of load

WAC 173-407-300 allows the load from specified and unspecified sources in a contract that provides a mix of types of power generation (such as a Bonneville Power Authority contract) to be averaged based on a formula.

Bonneville Power Authority (BPA) provided comments expressing concerns that they would have difficulty contracting with Washington Public Utility Districts (PUDs) if they had to specify all sources of power.[6] Therefore, section 300 of Chapter 173-407 WAC is included in the proposed rule. When an entity signs a contract that includes electricity from unknown sources, they are allowed to average the CO_2 emissions from all of the sources. In practice, this means that if a contract is for a specified share of power from renewables, up to 42 percent of their sources can be unspecified. Given that the Northwest has a very large current supply of renewable power, in practice this means they may be able to include as much existing and new fossil fuel-based power as necessary under long-term BPA contracts.

[6] "BPA will make decisions on rate design, power products to be offered, and power resources to be acquired based on the Regional Dialogue process. There are so many uncertainties as to how a rule on "unspecified sources" will affect the Regional Dialogue process. BPA believes it would be reasonable to allow more time for interested parties to consider this matter because an ill conceived rule could jeopardize the ability of consumer-owned utilities to acquire long-term power from the FCRPS. For these reasons, BPA believes the prudent and "practicable" course is for the Department not to implement a rule on "unspecified sources" at this time."

Table 1: Affected Power Plants

When would a power plant be required to meet the emission Performance Standard?								
	Instate				Out of state			
	upon start-up	new ownership interest	non-exempt upgrade	new long-term contract to supply baseload power	upon start-up	new ownership interest	non-exempt upgrade	new long-term contract to supply baseload power
Baseload generation								
Stand-alone								X
New	X	X	X	X				X
existing		X	X	X				
Cogeneration								
new	X	X	X					X
existing		X	X					X
Distributed generation								
new				X				X
existing				X				X
Non-baseload generation								
Seasonal								
new				X				X
existing				X				X
Emergency								
new				X				X
existing				X				X
Peaking power								
new				X				X
existing				X				X

Table assumes that the facility is not powered exclusively by renerwable fuels

Distributed generation is generation installed to supply the electrical needs of the facility it is located within. No power is sold to the grid. This is not cogeneration.

Cogeneration, aka combined heat and power, is a facility that produces both electrical energy and useful thermal energy. One or both forms of energy may be sold. Cogenreation facilities must meet certain FERC requirements to qualify.

Emergency generation are emergency generators, designed to operate on event of loss of grid power.

Peaking power plants and Seasonal power plants are facilities designed intended and permitted to operate at less than full time.

Peaking power plants operate solely to provide peak shaving power through the course of the day/year. They are not permitted for full time operation.

Seasonal power plants are plants that operate only during portions of the year with high power demand. They are not permitted for full time operation.

Once non-baseload generation becomes baseload generation through a new contract to supply baseload power, such units become existing baseload units.

What is required?

Chapter 80.80 RCW, created additional requirements with respect to greenhouse gases emissions. The law itself has a substantial impact without the proposed rules. However, it would be difficult for new power contracts in the state to be signed or new power plants sited and permitted for operation without adopting the proposed rules. The law and proposed rules adds a requirement for *permanent sequestration* of greenhouse gases above the 1,100 pounds of allowable emissions per megawatt hour (MWh) of electricity generated. The law does not define *permanent sequestration* or the specific plan requirements for designing, building, and monitoring a sequestration site or project. This is covered in the proposed rules.

The law and proposed rules also require that a new long-term financial commitment to buy electricity must meet the 1,100 pounds per MWh emissions performance standard. The rule specifies how a purchaser of electricity would determine if the proposed long-term financial commitment would meet the emissions performance standard.

WAC 173-218 is amended to include specific provisions for the design, permitting, implementation, closure and financial assurance requirements of an underground geologic sequestration project.

Baseline for Analysis

The baseline for this analysis is the law, as it can't be implemented without the existing rules or the proposed amendments.

Time Period for Analysis

This analysis is limited to a 12 year span reviewing likely choices available to power plants up to 2020. Ecology typically uses a 20 year period when evaluating rules. For major investments such as industrial plants, a longer period could be used. The law and the proposed rules allow CO_2 emissions to be reduced through perpetual storage, which would also require a longer time span for analysis. However, major potential changes make extending the time span less viable:

- The time span of the analysis affects not just discounting[7], but in this case, what should be evaluated. At the 2007 Electric Power Research Institute (EPRI) summer seminar,[8] only five percent of the participants (industry professionals) indicated they thought CO_2 capture would be commercially available by 2015. Only 24 percent thought it would be available by 2020, and only 15 percent by 2025. Over half of the participants do not expect it to be available for at least 20 years. The proposed rules limit CO_2 emissions for long-term baseload, but allows carbon capture and sequestration. If carbon capture and sequestration is not viable within the next 20 years, then it is the foregone energy that must be valued.

[7] Discounting uses an interest rate to reduce the value of costs which accrue in the future.
[8] Electric Power Research Institute, Electricity Solutions for a Carbon Constrained Future, http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2007-Fall/1016127_2007SummerSeminar.pdf

- On the other hand, 42 percent of the EPRI participants[9] believe mandatory CO_2 controls will be placed on the energy sector by 2010. Another 31 percent believe it will happen by 2012. The market forces that will affect the U.S. economy under carbon constraints and/or carbon pricing make 20 years too long a period to evaluate. It will change both the rules in the markets and the prices.

- Results from Wallula sequestration testing may change our understanding of geological sequestration.

- At the end of the five-year period, the law directs the Department of Community Trade and Economic Development (CTED) to revise the emission performance standard to reflect the capabilities of combined cycle natural gas fired turbine equipment available at that time. Based on current combined cycle power plant equipment, the standard would be revised downward to 830 – 860 lb/MWh if this update were to occur today. However, we don't know what will be viable five years from now. When revisions occur they must be evaluated. A change of this magnitude would likely alter the market outcome and therefore Ecology would count those costs for this analysis.

- As part of the 2008 legislative session, the legislature is considering a bill adding a greenhouse gas reporting requirement to RCW 70.94. The bill would direct Ecology to develop proposed legislation and other recommendations to implement a greenhouse gas cap and trade program that would become effective by 2012. If this series of proposed laws is passed by the legislature and the implementing rules are finalized per the timeframe in the current bill, the economic landscape of power plants and their greenhouse gas emissions will be very different than what exists today.

Finally, if the rule has a short-term of action because changes in state law significantly alter the constraints on the market, then the rule would only affect a very limited number of plants. This makes the unit costs of electricity and carbon a better mechanism for comparison.

Discount rates (interest rates) are used to compare values that accrue over time. This document relies heavily on the USDOE analysis of the cost of carbon dioxide capture. The USDOE models do not state the discount rate for modeling efforts that provide the unit cost of carbon capture and electricity. Ecology has requested this information so that the final analysis can have a coherent set of discount rates.

2. Analysis of Compliance Costs for Washington Businesses

The primary affect of the law and proposed rules taken together is to make it difficult to produce electricity with coal or with natural gas steam plants. Some companies may choose to shift to natural gas turbines.

Ecology could have counted small detailed costs involved with applying for sequestration, however that cost is unlikely to accrue. The shift in fuel is more expensive than these small costs but less expensive than carbon capture. Since carbon capture is so expensive that it is

[9] Ibid.

likely to make the electricity unmarketable, it is not likely to be selected for long term compliance by any company. Therefore the shift in fuel and all the costs associated with that are both the most likely and the appropriate measure of the costs. The total cost shift for this scenario involves significant differences in capital, labor, fuel costs and other items. Ecology has relied on USDOE estimates for this data.[10]

3. Quantification of Costs and Ratios

If the law and the proposed rules have any affect, and if affects more than one firm, then the impact will tend to be disproportionate. If construction of a plant were precluded then the revenue loss would be the highest possible cost that could be evaluated. It is not possible to estimate the size of the hypothetical plant. However, the disproportionate impact can be illustrated using a cost per MWh basis.

Table 2: Cost of electricity in Mills/KWh

Source	Mills per kWh
GE Energy	78
Conoco Phillips	75.3
Shell	80.5
Subcritical Pulverized Coal	64
Supercritical Pulverized Coal	63.3
Natural Gas Combined Cycle	68.4

A range of expected costs per MWh is available from USDOE data. The wholesale market price of electricity would have to be greater than or equal to these values in order for a company to want to produce and sell the electricity. Thus, these costs form a low estimate of the price that would have to be available to create entry into the market.

Taking the average of the coal based sources, $72/MWh, we can construct an estimate of the loss per MWh per employee for either a generator or a potential buyer, such as a Public Utility District.

Table 3: Cost of foregone revenue per MWh per employee by NAICS

Cost per MWh per Employee					
NAICS	221112	221121	221122	926130	All
Small Businesses			$ 3.59	******	$ 3.84
Large Business	$ 0.17	$ 0.96	$ 0.22		$ 0.32

*** data which would reveal the identity of companies or the number of employees is suppressed.

4. Actions Taken to Reduce the Impact of the Proposed Rule on Small Business

Ecology has done a variety of things to reduce the cost of the rule. These are listed below under the topic headings in the law. However, the primary cost reducing feature is averaging of load under (e) below.

(a) Reducing, modifying, or eliminating substantive regulatory requirements;

- Ecology considered a wide range of options for requiring a demonstration of compliance with the performance standard. Some advocated for regular and some for a one time

[10] USDOE, 2007, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, USDOE/NETL-2007/1281, Final Report (Original Issue Date, May 2007), Revision 1, Exhibit ES-7.

action when rule applicability is triggered while others advocated for a continuing compliance requirement based on annual reporting of compliance. Ecology chose to propose an annual compliance and reporting approach to be consistent with other air quality program requirements, including current emission inventory program requirements.

- In the performance standard applicability to contracts (section 300), proposed to use default values for some generation sources and for unspecified sources to simplify the effort of a utility to determine compliance for contracts. This allows the use of actual emission information, in the calculation for specified sources, but does not require actual emission information to be used.
- At one point the draft rule required monitoring of greenhouse gas emissions by all baseload power plants in Washington, as of the date the rule would go into effect, regardless of whether the facility was required to demonstrate compliance with the performance standard. Proposal has reduced the monitoring and reporting requirement to only those facilities and units that are subject to the applicability criteria - i.e. those which are new baseload plants, enter into a new long-term financial commitment, upgrade, new ownership interest, etc.
- The law does not contain a de minimis criterion for a new ownership interest (which triggers the requirement to comply with the standard). We propose a de minimis ownership interest change to trigger applicability. This will reduce work associated with the trading of a few shares or small percentages of a facility's output.
- The law does not include a de minimis usage of fossil fuel in a renewable resource generation facility. We have proposed a de minimis fossil fuel use to qualify as a renewable resource fueled generator. This de minimis is based on a criterion in several federal regulations. We have also defined what a renewable resource fuel is and utilized that definition in the proposed rule text. A de minimis fossil fuel usage is necessary for biomass fueled generation plants, because (1) you need to light the fire and fossil fuel (oil or natural gas) is usually used, (2) the cogeneration plants based on renewable fuels often have mandatory steam or electricity production contracts and need some sort of back-up fuel, and (3) occasionally the renewable fuel (especially wood waste) is too wet and needs supplemental fuel to properly burn. Without this de minimis, no electric generation facility that uses renewable fuels (biomass, landfill gas, etc) could qualify for the renewable energy source exemption in the law.
- The proposed rules will allow sequestration pilot projects to be permitted before meeting all of the data gathering requirements for a full permit.
- The proposed rules will allow the use of all existing geologic data previously collected for other activities to be used for site characterization.
- Geologic carbon sequestration projects will be permitted using the existing State Waste Discharge Permit Program instead of creating a unique permit program. Very few geologic sequestration permit applications are expected so if there were a unique permit program, the few projects would require permit fees that covered the total cost of the program.
- If a geologic sequestration project is associated with a fossil fuel power plant, which is likely, the same wastewater permit fee would cover all discharges including the carbon sequestration.

- The proposed rule will allow the use of all existing geologic data previously collected for other activities to be used for site characterization.
- During the discussions Ecology considered:
    - Requiring monitoring for each potable aquifer at a sequestration project and the unsaturated zone above the uppermost aquifer but chose to only require monitoring of the groundwater as close as practicable to the geologic sequestration formation.
    - Requiring evaluation and monitoring within 6 miles beyond the project boundary but chose to require this evaluation and monitoring 1 mile beyond the project boundary.
    - Requiring annual pressure testing of all injection wells but chose to require these tests every 5 years.
    - Requiring the post-closure period to extend for a set number of years after injection is complete but chose to allow the post-closure period to end once monitoring and modeling indicate that there is little continued environmental risk.
    - Requiring the project boundary to include the area of 100% of the carbon dioxide injected but chose to define the boundary as the calculated extend of 95 percent of the injected carbon dioxide mass 100 years after the end of injection.
    - Requiring a minimum number of deep characterization wells prior to permitting any site but chose to allow the number of wells to be determined based on site specific considerations.
- During the discussions Ecology considered not allowing:
    - Sequestration projects within 10 miles of any jurisdictional boundary, but chose to allow it as long as the project proponents addressed issues related to boundaries.
    - Sequestration projects within 10 miles of marine shorelines, but chose to allow as long as the project proponents addressed issues related to the shorelines.
    - Sequestration projects with more than 25 percent of the project area within a 100 year flood plain, but chose to allow as long as the project proponents addressed issues related to flood plains.
    - Sequestration projects where more than 25 percent of the land overlying is not physically accessible, but chose to allow as long as the project proponents addressed issues related to accessibility.
    - Sequestration projects with more than a low risk of seismic events, but chose to allow as long as the project proponents addressed issues related to seismic risks of the site.
    - Sequestration projects within 5 miles of any active faults, but chose to allow as long as the project proponents addressed any active (Holocene) faults within 5 miles.
    - The injection of carbon dioxide with any contaminants but chose to allow carbon dioxide as long as all known treatment technologies are used to remove contaminants.

(b) Simplifying, reducing, or eliminating record keeping and reporting requirements;

- Ecology considered requiring continuous monitoring for N2O at large plants, instead propose that large plants (above 25MW) do periodic emissions testing for the first year to establish a plant specific emission factor, and use that factor until an upgrade or other rule applicability triggering action occurs. For smaller plants, only emission factors derived from an authoritative source used, subject to ECY approval. For methane the same approach as for N2O is used.
- In the monitoring and recordkeeping and reporting requirements Ecology considered continuous stack monitoring of CO_2, and exhaust flow rate for all plant sizes. Proposal only requires this for facilities subject to the EPA Acid Rain program requirements, and allows the use of emission factor calculations as allowed by that program for natural gas combustion units. For all units not subject to the federal Acid Rain program allow the use of emission factors.
- For all plant sizes, an annual reporting requirement to ecology, done electronically for Acid Rain Program sources, piggybacked on their 4th quarter report to EPA, for all others a separate submittal to Ecology containing the required information.
- The minimum reporting requirements for geologic sequestration projects is the same as the minimum required for all state waste discharge permits.

(c) Reducing the frequency of inspections;

- For compliance with the emission performance standard, no inspections are required. However, the facilities subject to the federal Acid Rain program requirements to monitor CO2 emissions already and will continue to have required quality assurance and substitute data provisions to be followed. This proposed rule does not add new requirements but rather references those existing requirements. The federal program already requires this, and a different state program would be more burdensome on the facilities due to having to maintain duplicate and differing data.
- There is no set schedule for Ecology inspection of geologic sequestration projects.

(d) Delaying compliance timetables;

- For compliance with the emission performance standard, no inspections are required. However, the facilities subject to the federal Acid Rain program requirements to monitor CO_2 emissions already and will continue to have required quality assurance and substitute data provisions to be followed. This proposed rule does not add new requirements but rather references those existing requirements. The federal program already requires this, and a different state program would be more burdensome on the facilities due to having to maintain duplicate and differing data.
- There is no set schedule for Ecology inspection of geologic sequestration projects.
- There is no compliance dates in this proposed rule, just applicability dates in the law. Except for the enforcement of the sequestration plan requirements. The source is required to submit the sequestration plan or the sequestration program at the time of the submittal of the notice of construction application. The approval of this plan or program will be issued at the same time as the permit. If there is an instance of non-compliance with the emissions performance standard (EPS), there is a requirement to revisit the program or plan. There is a requirement to submit the new plan or program as soon as possible, but no later than 150 days after the annual report that compares actual performance with the EPS. We could have made the deadline sooner, but we decided to make it this length of time. The source should have enough internal information on meeting the EPS some

months before the end of the reporting period, and as such would prudently start work on a plan or program.

Geologic sequestration projects may begin with a pilot project prior to complying with all of the permitting requirements for a full-scale project.

(f) Any other mitigation techniques.
The most significant cost reduction in the proposed rules is the section that allows averaging of the load for contracted power supply involving multiple sources of electrical power. Section WAC 173-407-300 allows the load from specified and unspecified sources to be averaged based on a formula.

- Bonneville Power Administration provided comments expressing concerns that they would have difficulty contracting with Washington PUDs if they had to specify all sources of power.[11] Therefore section 300 of Chapter 173-407 is included in the proposed rule. When an entity signs a contract that includes purchases of electricity from unknown sources they are allowed to average the CO_2 emissions from all the sources. In practice this means that if the contract includes a specified share of power from renewables, they can have up to 42% of their sources be unspecified. Given that the Northwest has a very large current supply of renewable power, in practice this means they may be able to include as much existing and new fossil fuel based power as they find to be necessary under long-term BPA contracts.

5. The Involvement of Small Business in the Development of the Proposed Rule Amendments

The rule advisory committee contained representatives of both the consumer-owned utilities and the publicly owned utilities. The entities represented by these representatives are the small businesses that are directly affected by the rules.

6. The NAICS of Affected Industries

The rule may affect companies in 4 NAICS codes.

Table 4. NAICS Codes

Activity	NAICS
Fossil fuel electric power generation	221112
Electric bulk power transmission and control	221121
Electric power distribution	221122
Utility regulation and administration	926130

[11] "BPA will make decisions on rate design, power products to be offered, and power resources to be acquired based on the Regional Dialogue process. There are so many uncertainties as to how a rule on "unspecified sources" will affect the Regional Dialogue process. BPA believes it would be reasonable to allow more time for interested parties to consider this matter because an ill conceived rule could jeopardize the ability of consumer-owned utilities to acquire long-term power from the FCRPS. For these reasons, BPA believes the prudent and "practicable" course is for the Department not to implement a rule on "unspecified sources" at this time."

7. Impacts on Jobs

Ecology used the OFM input/output table[12] to estimate the potential labor impacts if a coal power plant were not opened. The size of the plant is unknown. In this case it is likely that electricity would be supplied by another typical source. The analysis assumes a shift of 10 MW of face place capacity from average coal production costs to average gas cogeneration production costs. Since this is a cost savings to the economy it acts as a reduction in expenditure (demand) in the model. The net change in demand based payments plugged into the model is $-335,000. This yields an annual loss of 4 jobs.

[12] http://www.ofm.wa.gov/economy/io/default.asp

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Appendix 1: USDOE Coal Data

Source:
http://tonto.eia.doe.gov/cfapps/STEO_Query/steotables.cfm?periodType=Annual&startYear=2005&startMonth=1&endYear=2009&endMonth=12&tableNumber=18
Download 1/16/2008

Table 6. U.S. Coal Supply, Consumption, and Inventories

	2005	2006	2007	2008	2009
Supply					
(Million short tons)					
Production	**1131.5**	**1162.7**	**1154**	*1144.5*	*1155.9*
Appalachia	**397.3**	**391.9**	**380.1**	*375*	*379.6*
Interior	**149.2**	**151.4**	**150.9**	*148.4*	*154.6*
Western	**585**	**619.4**	**623.1**	*621.1*	*621.7*
Primary Inventory Withdrawals	**6.2**	**-1.6**	**5.8**	*3.4*	*2.6*
Imports	**30.5**	**36.2**	**36.7**	*37.9*	*39*
Exports	**49.9**	**49.6**	**56.9**	*62.2*	*65.9*
Metallurgical Coal	**28.7**	**27.5**	**31.5**	*33.6*	*36.1*
Steam Coal	**21.3**	**22.1**	**25.4**	*28.3*	*29.7*
Total Primary Supply	**1118.2**	**1147.8**	**1139.6**	*1123.7*	*1131.6*
Secondary Inventory Withdrawals	**3.5**	**-41.1**	**-11.5**	*-0.2*	*4.1*
Waste Coal[a]	**13.4**	**14.4**	**14.2**	*15*	*15*
Total Supply	**1135.1**	**1121.1**	**1142.3**	*1138.4*	*1150.7*
Consumption					
(Million short tons)					
Coke Plants	**23.4**	**23**	**23.3**	*24*	*22.5*
Electric Power Sector[b]	**1037.5**	**1026.6**	**1047.9**	*1046*	*1058.4*
Retail and Other Industry	**65.1**	**62.7**	**64.8**	*68.4*	*68.7*
Residential and Commercial	**4.7**	**3.2**	**3.5**	*4.3*	*4.4*
Other Industry	**60.3**	**59.5**	**61.4**	*64*	*64.3*
Total Consumption	**1126**	**1112.3**	**1136**	*1138.4*	*1150.7*
Discrepancy[c]	**9.1**	**8.8**	**6.2**	*0*	*0*
End-of-period Inventories					
(Million short tons)					
Primary Inventories[d]	**35**	**36.5**	**30.8**	*27.3*	*24.7*
Secondary Inventories[e]	**109.3**	**150.4**	**161.9**	*162.2*	*158.1*
Electric Power Sector	**101.1**	**141**	**153.3**	*153.9*	*148.9*
Retail and General Industry	**5.6**	**6.5**	**6.2**	*6*	*6*
Coke Plants	**2.6**	**2.9**	**2.3**	*2.2*	*2.2*
Coal Market Indicators					
Coal Miner Productivity					
(Tons per hour)	**6.36**	**6.26**	**6.16**	*6.06*	*6*
Total Raw Steel Production					
(Million short tons per day)	**0.285**	**0.289**	**0.293**	*0.292*	*0.296*
Cost of Coal to Electric Utilities					
(Dollars per million Btu)	**1.54**	**1.69**	**1.77**	*1.81*	*1.85*

Appendix 2 USDOE Natural Gas Data

Source:
http://tonto.eia.doe.gov/cfapps/STEO_Query/steotables.cfm?periodType=Annual&startYear=2005&startMonth=1&endYear=2009&endMonth=12&tableNumber=16
Download: 1/16/2008

Table 5c. U.S. Regional Natural Gas Prices

Dollars per Thousand Cubic Feet

	2005	2006	2007	2008	2009
Wholesale/Spot					
U.S. Average Wellhead	7.26	6.4	6.37	6.87	7.09
Henry Hub Spot Price	8.85	6.93	7.17	7.78	7.92
Residential					
New England	15.49	17.55	16.62	16.82	17.23
Middle Atlantic	13.54	15.64	15.27	16.03	16.1
East North Central	11.76	12.38	11.87	12.15	12.35
West North Central	11.85	12.57	12.35	12.38	12.98
South Atlantic	15.61	17.18	16.81	16.78	17.19
East South Central	13.87	15.48	14.5	15.04	14.92
West South Central	12.56	13.46	12.61	13.28	13.72
Mountain	10.9	12.02	11.03	11.55	12.07
Pacific	11.75	12.02	11.99	12.37	12.74
U.S. Average	12.7	13.75	13.27	13.65	13.95
Commercial					
New England	13.63	14.93	14.03	14.29	14.59
Middle Atlantic	12.01	12.75	12.18	13.39	13.46
East North Central	10.66	11.41	10.76	11.25	11.61
West North Central	10.6	10.93	10.53	10.92	11.32
South Atlantic	12.9	13.63	12.84	13.1	13.34
East South Central	12.55	13.45	12.51	12.97	13.2
West South Central	10.62	10.68	10.29	10.77	11.03
Mountain	9.46	10.63	9.75	10.45	10.81
Pacific	10.52	10.9	10.92	11.08	11.48
U.S. Average	11.34	11.99	11.41	11.97	12.26
Industrial					
New England	12.54	12.92	12.21	12.59	12.77
Middle Atlantic	10.61	11.01	10.91	11.39	11.47
East North Central	9.83	9.74	9.62	9.88	10.17
West North Central	8.86	8.44	8	8.5	8.78
South Atlantic	10.41	9.72	9.27	9.62	9.97
East South Central	9.68	9.64	8.72	9.4	9.48
West South Central	7.97	6.89	6.95	7.53	7.82
Mountain	8.37	9.49	8.98	9.4	9.56
Pacific	7.14	7.96	8.3	8.22	8.61
U.S. Average	8.56	7.86	7.67	8.24	8.5

Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories

	2005	2006	2007	2008	2009
Supply *(Billion cubic feet per day)*					
Total Marketed Production	**51.86**	**53.1**	**54.43**	*55.28*	*55.41*
Alaska	**1.34**	**1.22**	**1.24**	*1.28*	*1.27*
Federal GOM[a]	**8.58**	**7.95**	**7.67**	*8.27*	*8.04*
Lower 48 States (excl GOM)	**41.94**	**43.93**	**45.52**	*45.73*	*46.1*
Total Dry Gas Production	**49.45**	**50.62**	**52.04**	*52.8*	*52.92*
Gross Imports	**11.89**	**11.47**	**12.47**	*12.07*	*12.4*
Pipeline	**10.16**	**9.87**	**10.33**	*9.51*	*9.18*
LNG	**1.73**	**1.6**	**2.14**	*2.56*	*3.23*
Gross Exports	**2**	**1.98**	**2.03**	*1.96*	*1.87*
Net Imports	**9.9**	**9.49**	**10.44**	*10.11*	*10.53*
Supplemental Gaseous Fuels	**0.17**	**0.18**	**0.17**	*0.18*	*0.18*
Net Inventory Withdrawals	**0.14**	**-1.2**	**0.46**	*0.09*	*0.03*
Total Supply	**59.67**	**59.09**	**63.11**	*63.18*	*63.67*
Balancing Item[b]	**0.64**	**0.23**	**-0.23**	*0.07*	*0.21*
Total Primary Supply	**60.3**	**59.32**	**62.88**	*63.24*	*63.88*
Consumption *(Billion cubic feet per day)*					
Residential	**13.22**	**11.97**	**12.96**	*13.21*	*13.22*
Commercial	**8.22**	**7.77**	**8.27**	*8.34*	*8.38*
Industrial	**18.07**	**17.79**	**18.07**	*18.15*	*18.18*
Electric Power[c]	**16.08**	**17.05**	**18.68**	*18.73*	*18.26*
Lease and Plant Fuel	**3.05**	**3.08**	**3.14**	*3.1*	*3.14*
Pipeline and Distribution Use	**1.6**	**1.6**	**1.68**	*1.64*	*1.62*
Vehicle Use	**0.06**	**0.07**	**0.07**	*0.08*	*0.08*
Total Consumption	**60.3**	**59.32**	**62.88**	*63.24*	*63.88*
End-of-period Inventories *(Billion cubic feet)*					
Working Gas Inventory	**2635**	**3070**	**2840**	*2807*	*2794*
Producing Region[d]	**748**	**953**	**910**	*895*	*868*
East Consuming Region[d]	**1511**	**1726**	**1525**	*1542*	*1558*
West Consuming Region[d]	**376**	**391**	**405**	*370*	*368*

Appendix 3: Electricity Pricing Data

Source: http://tonto.eia.doe.gov/cfapps/STEO
Downloaded 1/16/08

Table 7c. U.S. Regional Electricity Prices

Cents per Kilowatthour

	2005	2006	2007	2008	2009
Residential Sector					
New England	13.4	16	16.6	17	17.6
Middle Atlantic	12.5	13.4	14	14.2	14.6
East North Central	8.4	9.1	9.7	9.8	10.1
West North Central	7.8	8.1	8.2	8.3	8.5
South Atlantic	8.8	9.8	10	10.1	10.4
East South Central	7.4	8.2	8.2	8.3	8.6
West South Central	10	11.5	11.2	11.5	11.9
Mountain	8.7	9	9.2	9.4	9.6
Pacific	10.4	11.6	11.8	12	12.4
U.S. Average	9.4	10.4	10.6	10.8	11.1
Commercial Sector					
New England	11.9	14.5	14.6	15.1	15.7
Middle Atlantic	11.8	12.7	13.1	13.3	13.7
East North Central	7.7	8.2	8.6	8.7	8.8
West North Central	6.3	6.6	6.7	6.8	6.9
South Atlantic	7.5	8.5	8.7	8.9	8.9
East South Central	7.2	7.9	8	8.1	8.4
West South Central	8.4	9.3	9.4	9.6	10
Mountain	7.4	7.6	7.7	7.9	8
Pacific	10.4	11.2	11.2	11.5	11.9
U.S. Average	8.7	9.5	9.6	9.9	10.1
Industrial Sector					
New England	9.1	11.6	12.5	13.1	13.5
Middle Atlantic	7.3	7.8	8	8.1	8.3
East North Central	4.9	5.4	5.8	5.8	6
West North Central	4.7	4.9	5.1	5.2	5.3
South Atlantic	5.3	5.5	5.6	5.8	5.9
East South Central	4.4	4.8	5.1	5.2	5.4
West South Central	6.6	7.2	7.1	7.3	7.6
Mountain	5.5	5.5	5.7	5.8	5.9
Pacific	7.5	7.9	7.9	7.8	8.1
U.S.Average	5.7	6.2	6.4	6.5	6.7
Average All Sectors*					
New England	12	14.5	15	15.4	16
Middle Atlantic	11.1	11.9	12.4	12.6	13
East North Central	6.9	7.5	7.9	8	8.2
West North Central	6.4	6.6	6.8	6.9	7
South Atlantic	7.6	8.4	8.6	8.8	9
East South Central	6.2	6.8	7	7.1	7.3
West South Central	8.5	9.4	9.4	9.6	10
Mountain	7.3	7.5	7.7	7.8	8
Pacific	9.7	10.6	10.7	10.9	11.3
U.S.Average	8.1	8.9	9.1	9.3	9.6

Appendix 4: National Discussions on Limits to CO_2 Emissions and Coal

Part of this analysis indicates that national discussions on a greenhouse gas tax or a cap-and-trade program have had a chilling effect on investment in coal. This relies on the assumption that industry is aware that there will be in the future, some significant form of restriction on CO_2 emissions and further that the expectations are already having an effect on coal development. This comes partly from The Future of Coal.[13]

As MIT observed:

> "Any serious efforts by government or industry to address greenhouse gas emissions and global warming in the near term would impose a price or charge on carbon or constrain the use of CO_2-emitting fuels in some manner."

Their second finding in the conclusions section is that:

> "Finding #2: A global carbon charge starting at $25 per ton of CO_2 emitted (or nearly $100 per tonne of carbon), imposed initially in 2015 and rising at a real rate of 4% per year, will likely cause adjustments to energy demand, supply technologies and fuel choice sufficient to stabilize mid-century global CO_2 emissions from all industrial and energy sources at a level of 26 to 28 gigatons of CO_2 per year. Depending on the expansion of nuclear power, the use of coal increases from 20% to 60% above today's level, while CO_2 emissions from coal are {96 MIT STUDY ON THE FUTURE OF COAL} reduced to half or a third of what they are today. This level of carbon charge implies an increase in the bus bar cost of U.S. electricity on average of about 40%, or about 20% of the retail cost. A significant contributor to the emissions reduction from coal is the introduction of CCS, which is utilized as an economical response to carbon charges at these levels. In the EPPA model simulations, approximately 60% of coal use employs CCS by 2050 with this carbon charge."

They further evaluate the trend in citizen willingness to pay for greenhouse gas reductions and find it to be significant:

> "As interesting as the levels of support for the taxes are the changes over time. We repeated the survey in 2006 and found a 50 percent increase in willingness to pay. The median response was approximately $15 more a month (or a 15 percent levy on the typical electricity bill), compared with just $10 in 2003. The average amount came to $21 per month. The rising amount that the typical person would pay was matched by a decline in the percent unwilling to pay anything. In 2003, 24 percent of those surveyed said they were unwilling to pay anything. Three years later, a similarly constructed sample answered the identical series of questions, and the percent unwilling to pay anything fell to 18 percent, a statistically significant drop. The rise in willingness to pay resulted in large part from the increased recognition of the importance of the problem. The percentage of those who consider global warming

[13] Ansolabehere, Stephen, Janos Beer, John Deutch, A. Denny Ellerman, S. Julio Friedmann, Howard Herzog, Henry D. Jacoby, Paul L. Joskow, Gregory Mcrae, Richard Lester, Ernest J. Moniz, Edward Steinfeld, James Katzer, 2007, The Future of Coal, Massachusetts Institute of Technology, http://web.mit.edu/coal/.

> a top-tier environmental concern rose from 20 percent to 50 percent. Those who did not rank global warming as one of the top two environmental problems in 2006 were willing to pay, on average $16 per month in 2006, while those who did rank global warming as one of the top environmental concerns in the country {Public Attitudes Towards Energy, Global Warming, and Carbon Taxes 91} were willing to pay $27 a month. In addition, willingness to pay among those who are concerned with this problem has risen considerably. Among those who consider global warming one of our chief environmental problems willingness to pay rose from $17 a month in 2003 to $27 a month in 2006. If global warming continues to rise as a concern, we expect to see growth, possibly very rapid growth, in willingness to pay fuel taxes that target greenhouse gas emissions."

Part of the confusion in the market comes from the expectation that coal plants may be grandfathered in and obtain large grants for CO_2 emissions. Doing this for new plants that are currently only "in the pipeline" would reduce assistance for populations that depend on plants that exist now. MIT indicates:

> "There is, however, a serious policy problem in that prospective investors in either SCPC or IGCC plants without CO_2 capture, may anticipate that potentially they will be "grandfathered" or "insured" from the costs of future carbon emission constraints by the grant of free CO_2 allowances to existing coal plants, including those built between today and the start of the cap-and-trade system. The possibility, indeed political likelihood of such grandfathering, means that there is a perverse incentive to build coal plants early—and almost certainly these will be SCPC plants—to gain the potential benefits of these future allowances while also enjoying the higher electricity prices that will prevail in a future control regime. The net {100 MIT STUDY ON THE FUTURE OF COAL} effect is that early coal plant projects realize a windfall from carbon regulation and thus investment in these projects will raise the cost of future CO_2 control.

Recommendation #6b: Congress should act to close this potential "grandfathering" loophole before it becomes a problem for new power plants of all types that are being planned for construction."

Given the concerns in the industry over the cost of dealing with carbon, some have suggested federal support for the construction of capture ready coal plants. However MIT indicates:

> "Some suggest that the uncertainty about the imposition of a future carbon charge justifies offering federal support for a portion of the initial investment cost required to build new coal combustion plants without carbon capture and sequestration today, so that if a carbon emission charge were imposed in the future, the carbon capture and sequestration retrofit cost would be lower. We do not believe that sufficient engineering knowledge presently exists to define the relationship of the extent of pre-investment to the cost of future retrofit, and the design percentage of CO_2 removed. Moreover, the uncertainty about when a carbon charge might be imposed makes it difficult (for either a private investor or the government) to determine the value of incurring a cost for a benefit that is realized, if at all, at some uncertain future time. Other than a few low-cost measures such as providing for extra space on the plant site and considering the potential for geologic CO_2 storage in site selection, the

opportunity to reduce the uncertain eventual cost of CCS retrofit by making preparatory investment in a plant without CO_2 capture does not look promising. In sum, engineering and policy uncertainties are such that there is no meaningful basis to support an investment decision to add significant “capture ready” features to IGCC or pulverized coal plants, designed and optimized for operation without CO_2 capture.”

Appendix 5: Other Items that May Affect Energy Prices

Natural Gas Price Shifts

There have been increases in the price of natural gas so this may understate the cost of shifting from coal to natural gas. The expected price shift for natural gas may be somewhat higher than for coal.[14] The USDOE is forecasting an increase in the price of natural gas in the Pacific region of 3.7% to 5.1% between 2007 and 2009.[15] The increase in the price for coal is forecast to be 4.5% for the same time period. But the highest estimated price shift differential is not large. Therefore 8.1% seems a safe increase to estimate.

Rates are Averages

For comparison purposes the average retail cost of electricity for Washington was $63.60 per MWh in 2007.[16] Puget Power's residential rate including both their conservation and green power programs was $87.42 per MWh. This price includes wheeling power to the customers. For example, in the USDOE's Pacific Region they forecast the price of industrial electricity supplied to be 81 mills per kWh. This would cover the cost of coal power but not the cost of CO_2 capture. The 2005 WECC[17] average wholesale price of power was $48 per MWh. Note that this includes low cost hydropower and nuclear. The marginal cost is higher. Another possible comparison is to alternatives such as Wind, which USDOE indicates may cost $40 to $60 per MWh.[18] This latter is for comparison only because intermittent power supplies such as wind are less useful than supply that can meet baseload. Intermittent power can reach a tipping point somewhere between 15% and 30% of the load where it becomes less viable and more expensive to absorb it into the system. Until the supply of intermittent power swamps the ability of the grid to offset it, it is a lower price than that reported in USDOE's evaluation of coal. If it is necessary to use batteries to store the wind power, then the cost doubles.

Prices for Viable carbon capture and sequestration in the Future

As the literature looks for a price at which sequestration becomes viable, high prices are cited.

- An MIT study estimates the carbon tax or charge that would be necessary to make sequestration viable. For future uses of coal the MIT study[19] finds that:

  "Successful implementation of CCS will inevitably add cost for coal combustion and conversion. We estimate that for new plant construction, a CO_2 emission price of

[14] http://www.eia.doe.gov/steo data queries on left hand side of the page allow access to tables 5a, 5c, and 6 for comparison purposes.

[15] Day to day price movements may have been more volatile than this implies but averages necessarily smooth this.

[16] Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date. Downloaded 1/23/08, http://www.eia.doe.gov/cneaf/electricity/epa/epat7p4.html

[17] Western Systems Coordinating Council.

[18] http://www1.eere.energy.gov/windandhydro/wind_ad.html Downloaded 1/22/08. Note: it is unclear whether this is with or without subsides.

[19] Ansolabehere, Stephen, Janos Beer, John Deutch, A. Denny Ellerman, S. Julio Friedmann, Howard Herzog, Henry D. Jacoby, Paul L. Joskow, Gregory Mcrae, Richard Lester, Ernest J. Moniz, Edward Steinfeld, James Katzer, 2007, The Future of Coal, Massachusetts Institute of Technology, http://web.mit.edu/coal/.

approximately $30/tonne (about $110/tonne C) would make CCS cost competitive with coal combustion and conversion systems without CCS. This would be sufficient to off set the cost of CO_2 capture and pressurization (about $25/tonne) and CO_2 transportation and storage (about $5/tonne). This estimate of CCS cost is uncertain; it might be larger and with new technology, perhaps smaller."

- Bohm et al [2007] examines the effects of carbon prices on optimal investment at three types of plants:

  "The results of the analysis show that a baseline PC plant is the most economical choice under low CO_2 prices, and IGCC plants are preferable at higher CO_2 prices (e.g., an initial price of about $22/t CO2 *{$24/tonne CO2}* starting in 2015 and growing at 2%/year). Little difference is seen in the lifetime NPV costs between the IGCC plants with and without pre-investment for CO_2 capture. … The difference in lifetime emissions become significant only under mid-estimate CO_2 price scenarios (roughly between $20 and 40/t CO_2 *{$22 and $44/tonne CO2}*) where IGCC plants will retrofit sooner than a PC plant."[20]

- The IEA places the cost of CO_2 avoided at just under $30 for IGCC slurry feed plants.[21]

With an additional $24 to $30/tonne CO_2 however coal may not be able to compete with other sources of electricity.

Costs of Offsets vs Sequestration

The only proposal brought before EFSEC indicated they wanted to explicitly cut off the option of sequestration at $5 per ton. This tends to imply that a sequestration cost above $5 per ton is not competitive.

"The measure of technological and economic feasibility for geological or other permanent sequestration, including carbon capture, compression, transport and storage, is a cost of $5/tonne CO_2 ($240-270 million) inclusive of the $50 million carbon capture investment."[22]

EU Actions as an Indicator of Long-term Possible Costs

The EU is proceeding with reductions in CO_2 that are quite expensive. "It is estimated that acting now will limit the inevitable cost of curbing climate change to well below 1% of GDP, as opposed to the 5-20% needed if no action is taken (Stern report). This works out at roughly 150 euros {$223} per person each year until 2020 {total of $2,905 per person over 13 years}. What's more, savings on oil and gas imports alone – as the EU reinforces energy security - could amount to as much as €50bn {$74.5 billion} per year."[23]

[20] Bohm, Mark C., Howard J. Herzog, John E. Parsons, Ram C. Sekar, Capture-ready coal plants—Options, technologies and economics, International Journal of Greenhouse Gas Control, 1 (2007), 113 – 120.

[21] http://www.ieagreen.org.uk/glossies/co2capture.pdf, Capturing CO2, Figure 4.

[22] Pacific Mountain Energy Center Greenhouse Gas Reduction Plan, Submitted to Washington Energy Facility Site Evaluation Council, Application 2006-01, pg 7 item i.

[23] http://ec.europa.eu/news/energy/080123_1_en.htm downloaded 1/24/08.