August 30, 2007

Edward R. Schild,
Designated Representative
Puget Sound Energy
10885 NE 4th Street
P.O. Box 97034, PSE-09S
Bellevue, WA 98009-9734

Re: Petition to Use an Alternative Method to Account for Sulfur Dioxide Emissions Prior to Initial Monitoring System Certification, for Units CT1, CT2, and CT3 at the Encogen Generating Station (Facility ID (ORISPL) 7870)

Dear Mr. Schild:

The United States Environmental Protection Agency (EPA) has reviewed the September 19, 2006 petition submitted by Puget Sound Energy (PSE) under 40 CFR 75.66, in which PSE requested to use an alternative method to account for sulfur dioxide (SO_2) emissions prior to certification of the required continuous monitoring systems for Units CT1, CT2, and CT3 at the Encogen Generating Station. EPA approves the petition, in part, as discussed below.

Background

PSE owns and operates three 41 megawatt combined-cycle combustion turbines, Units CT1, CT2, and CT3 at the Encogen Generating Station (Encogen) located in Whatcom County, Washington. The units primarily combust natural gas. Diesel fuel is occasionally burned as a backup fuel (usually for less than 75 hours per year). Encogen produces electricity for sale to the grid and also provides steam to an adjacent industrial facility. Units CT1, CT2, and CT3 are subject to the Acid Rain Program (ARP). Therefore, PSE is required to continuously monitor and report SO_2, nitrogen oxides (NO_x), and carbon dioxide (CO_2) emissions and heat input for these units, in accordance with 40 CFR Part 75.

According to PSE, Encogen was originally constructed in 1993 by Encogen Northwest, L.P., was a qualifying facility with a qualifying power purchase commitment as of November 15, 1990, and was exempt from the Acid Rain Program under 40 CFR 72.6(b)(5). PSE states that, on November 1, 1999, it acquired Encogen Northwest, L.P., thereby making Encogen Northwest, L.P. a wholly-owned subsidiary of PSE. PSE also states that it was unaware that this business transaction resulted in Encogen losing its qualifying facility status and therefore its exemption, pursuant to 40 CFR 72.6(a)(3)(v), and in Units CT1, CT2, and CT3 becoming subject to the ARP and thus to the continuous emission monitoring and reporting requirements of Part 75. Solely for purposes of responding to PSE's petition, EPA is assuming that the units were exempt from the ARP under §72.6(b)(5) and that the units first became affected units subject to ARP requirements on November 1, 1999.

Under 40 CFR 72.9(c)(3)(iv), PSE is accountable for the SO_2 emissions from Units CT1, CT2, and CT3 starting at the continuous monitoring system certification deadline specified in 40 CFR 75.4(c)(2). Under §75.4(c)(2), the owner or operator must ensure that all required monitoring systems are installed and certified no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date on which the unit first operates after becoming subject to the ARP. As previously noted, it is assumed that Units CT1, CT2, and CT3 became ARP-affected units on November 1, 1999. The 90th unit operating day after that date was February 1, 2000, which is less than 180 calendar days after November 1, 1999. Therefore, PSE was required to certify Part 75-compliant monitoring systems and to begin reporting emissions data for Units CT1, CT2, and CT3 no later than February 1, 2000.

However, Encogen did not record or report emissions data using certified Part 75 monitoring systems until monitoring systems were certified for the units (i.e., for Unit CT1 on April 25, 2006, for Unit CT2 on April 12, 2006, and for Unit CT3 on April 19, 2006). Therefore, for the period from February 1, 2000 through April 25, 2006 for Unit CT1, through April 12, 2006 for Unit CT2, and through April 19, 2006 for Unit CT3, section 2.4 of Appendix D would require PSE to use, as substitute data to calculate the hourly SO_2 emissions from Units CT1, CT2, and CT3: the units' maximum potential values for fuel flow rate, sulfur content, and gross calorific value (GCV) to account for the combustion of diesel; and 1.5 times the sum of the highest sulfur content value of the natural gas used during the 30 days before the substitute data period and the maximum amount of sulfur from the odorant added to the natural gas (0.26 gr/100 scf) to account for the combustion of natural gas. Believing that the use of Appendix D substitute data to estimate emissions would grossly overstate the SO_2 emissions from these units, PSE submitted a petition to EPA under §75.66 on September 19, 2006, requesting to use an alternative substitute data calculation methodology.

The proposed alternative substitute data calculation methodology is based on Appendix D but uses the monthly average sulfur content of the natural gas plus the maximum amount of sulfur from the odorant, instead of using 1.5 times the sum of the highest sulfur content value of the natural gas and the maximum amount of sulfur from the ordorant. According to PSE, the proposed methodology would provide conservative estimates of SO_2 emissions of similar quality to those obtainable using Appendix D.

To quantify the natural gas consumption, PSE proposed to use historical fuel flow rate data from billing records provided by Cascade Natural Gas, the company that operates the main pipeline supplying natural gas to Encogen. Section 2.1.4.2 of Appendix D allows a fuel flowmeter used for commercial billing to be used to measure, record, and report hourly fuel flow rates, provided that the billing company and the end user do not have any common owners and are not owned by subsidiaries or affiliates of the same company. The commercial billing meter that measures the natural gas supplied to Encogen meets this requirement. Hourly gas flow rate and GCV data were available from June 1, 2002 until April 25, 2006; however, prior to June 1, 2002, only daily average values were available.

To determine the sulfur content of the natural gas, PSE proposed to use data provided by Williams Pipeline, the operator of the regional branch of the main pipeline that supplies Encogen with natural gas. From February 1, 2000 through December 31, 2002, daily average values of the fuel's sulfur content were available. From January 1, 2003 until April 25, 2006, however, hourly sulfur content data were provided. At a point between the sulfur sampling location and the Encogen facility, an odorant, containing 0.13 to 0.26 grains of sulfur per 100 standard cubic feet (gr/100 scf), is added to the natural gas for safety reasons. To ensure that the SO_2 emissions estimates for Units CT1, CT2, and CT3 would be conservative, PSE added the maximum sulfur content added by the odorant (i.e., 0.26 gr/100 scf) to the results of each monthly average sulfur sample before performing the emissions calculations.

To estimate the monthly SO_2 emissions for Units CT1, CT2, and CT3 from natural gas combustion during the period in question, PSE used the following equation, which is similar to Equation D-4 in Appendix D of Part 75:

$$SO_{2\ mass} = \left(\frac{2.0}{7000}\right) x\ GAS_{total}\ x\ S_{avg}$$

Where:

$SO_{2\ mass}$ = Monthly SO_2 mass emissions due to combustion of natural gas (lb)

GAS_{total} = Total quantity of natural gas combusted in the month (100 scf)

S_{avg} = Monthly average sulfur content of the natural gas (gr/100 scf)

2.0 = Ratio of lb SO_2/lb S

7000 = Conversion factor for grains to lb

For each calendar year, the monthly mass emissions values were summed, and the sum was divided by 2000 lb/ton to convert it to tons of SO_2.

To estimate the monthly SO_2 mass emissions from diesel oil combustion during the period in question, PSE used the following equation, which is similar to Equation D-2 in Appendix D:

$$SO_{2\ mass} = 2.0\ x\ OIL_{mass}\ x\ \left(\frac{\%S_{oil}}{100}\right)$$

Where:

$SO_{2\ mass}$ = Monthly mass emissions of SO_2 from oil combustion, lb

OIL_{mass} = Total mass of oil combusted in the month, lb

$\%S_{oil}$ = Percentage of sulfur by weight in the oil

2.0 = Ratio of lb SO_2/lb S

In the absence of quality-assured oil flow rate data, PSE determined each monthly value of OIL_{mass} in the equation above by multiplying the maximum potential fuel flowrate (lb/hr), as defined in section 2.4.2.1 of Appendix D, by the number of hours of diesel oil combustion in the month. PSE also used the maximum sulfur content allowed by its fuel oil contract (i.e., 0.05% S) in the equation. For each calendar year, the monthly SO_2 mass emissions values were summed, and the sum was divided by 2000 lb/ton to convert it to tons of SO_2.

A summary of SO_2 emissions calculated by PSE for the time period extending from February 1, 2000 to April 25, 2006 is shown in Table 1, below.

Table 1: Petitioned SO_2 Mass Emissions from Encogen Units CT1, CT2, and CT3

Year	SO_2 from Natural Gas (Tons)	SO_2 from Diesel (Tons)	Total SO_2 (Tons)
2000*	14.1	0.5	14.6
2001	19.3	0.7	20.0
2002	13.9	0.5	14.4
2003	7.4	0.8	8.2
2004	5.4	0.1	5.5
2005	4.5	0.0	4.5
2006**	1.3	0.0	1.3
Total	**65.9**	**2.6**	**68.5*** **

* February 1, 2000 through December 31, 2000, only
** January 1, 2006 through April 25, 2006 for Unit CT1, April 12, 2006 for Unit CT2, and April 19, 2006 for Unit CT3, only
*** The Agency notes that the cumulative emissions values provided by PSE in the September 19, 2006 petition were incorrectly summed (i.e., the petition showed total SO_2 tons as 62.7, rather than 68.5).

EPA's Determination

EPA approves PSE's petition, in part, for an alternative substitute data methodology for calculating the SO_2 emissions from Encogen Units CT1, CT2, and CT3 in the time period from February 1, 2000 through monitor certification (for Unit CT1 on April 25, 2006, for Unit CT2 on April 12, 2006, and for Unit CT3 on April 19, 2006). However, for the reasons given below, the approved values for the annual and cumulative SO_2 emissions values are the ones shown in Table 2, below, rather than the ones requested in PSE's petition and shown in Table 1 above.

Table 2: Accepted SO_2 Mass Emissions from Encogen Units CT1, CT2, and CT3

Year	SO_2 from Natural Gas (Tons)	SO_2 from Diesel (Tons)	Total SO_2 (Tons)
2000*	18.7	0.5	19.2
2001	24.5	0.7	25.2
2002	16.5	0.5	17.0
2003	9.8	0.8	10.6
2004	6.5	0.1	6.6
2005	5.3	0	5.3
2006**	1.5	0	1.5
Total	**82.8**	**2.6**	**85.4**

* February 1, 2000 through December 31, 2000, only
** January 1, 2006 through April 25, 2006 for Unit CT1, April 12, 2006 for Unit CT2, and April 19, 2006 for Unit CT3, only

PSE's proposed substitute data calculation methodology includes a number of conservative assumptions to prevent under-reporting of the SO_2 emissions for the time period in question. In particular:

- The natural gas fuel flow rate data include a small amount of gas burned in an on-site boiler that is not subject to the Acid Rain Program. Therefore, the total gas volume used in the calculations is an overestimate;

- All of the natural gas combusted was assumed to contain the maximum amount of sulfur added by the odorant (i.e., 0.26 gr/scf). Therefore, the total sulfur content of the gas used in the calculations is an overestimate;

- The assumed sulfur content of the diesel oil (0.05% S) is the highest value allowed by the fuel contract for the units. Fuel sampling data obtained during the time period in question confirmed that the actual sulfur content of the diesel oil was less than 0.05% S. Therefore, the total sulfur content of the oil used in the calculations is an overestimate; and

- The maximum potential fuel flow rate is assumed for all hours of diesel oil combustion. Therefore, the total mass of fuel oil used in the calculations is an overestimate.

However, the primary purpose of requiring the use of substitute data is "[t]o encourage the use of CEMS as the primary method for determining emissions and, at the same time, foster effective operations and maintenance programs by putting in place strong incentives for minimizing monitor downtime and maximizing data capture rates."[1] In addition, substitute data

[1] 58 FR 3590, 3635 (Jan. 11, 1993).

are used to ensure that emissions are not under-reported and that the environment is therefore protected by the deduction of allowances covering the reported emissions.

In order to determine if PSE's proposed calculation methodology for substitute data is sufficiently conservative to provide a strong incentive for compliance with monitoring and reporting requirements and to ensure protection of the environment, EPA developed estimates of the SO_2 emissions from Units CT1, CT2 and CT3 using three different methods for the time period in question. The first emissions estimate was made using the standard substitute data approach in Appendix D of Part 75, which is based on: 1.5 times the sum of the highest sulfur content value of the natural gas used during the 30 days before the substitute data period and the maximum amount of sulfur added by the odorant (0.26 gr/100 scf); and maximum potential values for parameters related to the diesel oil. This resulted in estimated SO_2 emissions of 154.8 tons.[2] The second estimate, aimed at more closely approximating the units' actual SO_2 emissions, was made by using Encogen's proposed methodology but replacing the assumption that a maximum amount of sulfur added by the odorant (0.26 gr/100 scf) was added to the gas continuously, which was an assumption made to overstate, or at least ensure no understatement of, the units' emissions.[3] Instead, the amount of sulfur added by the odorant was assumed to be 0.20 gr/100 scf, the average of the range of potential odorant sulfur values. This resulted in estimated SO_2 emissions of 64.5 tons.[4] The third estimate used Encogen's proposed methodology but replaced each monthly average value of the sulfur content of the natural gas combusted with the 90th percentile value of such sulfur content for that month. This resulted in SO_2 emissions of 85.4 tons.[5]

In view of these results, EPA concludes the following. First, the Appendix D substitute data approach results in an estimate that grossly overestimates the SO_2 emissions from Units CT1, CT2, and CT3 (i.e., that is about two and one-half times EPA's second estimate that approximates actual emissions) and is inappropriate in this case. Second, Encogen's proposed calculation methodology results in an estimate that is essentially the same as EPA's second estimate approximating the units' actual emissions. However, Encogen's estimate does not provide a strong incentive for compliance. Consequently, the proposed methodology is not sufficiently conservative in light of the purposes of substitute data. Finally, the third estimate, based on using the 90th percentile monthly values of the natural gas sulfur content, is about one and one-third times EPA's estimate approximating actual emissions and is sufficiently conservative for substitute data purposes in this case.

For these reasons, EPA approves PSE's petition, in part, and approves the use of the substitute data reflected in Table 2 above, in lieu of the alternative substitute data requested by

[2] This total also includes 2.6 tons of SO^2 due to the combustion of oil, which was calculated based on maximum potential fuel flow rate and maximum total sulfur content allowed by contract.
[3] The other conservative assumptions, described above, made in Encogen's proposed methodology likely had a much smaller effect on the total emissions estimate than the assumption concerning ordorant.
[4] See n. 2.
[5] See n.2.

PSE's petition (which are reflected in Table 1).[6] EPA's determination relies on the accuracy and completeness of the information provided by PSE in the September 19, 2006 petition and attachments and subsequent clarifying emails with attachments and is appealable under Part 78. If you have any questions regarding this determination, please contact Travis Johnson at (202) 343-9018 or at johnson.travis@epa.gov. Thank you for your continued cooperation.

Sincerely,

/s/
Sam Napolitano, Director
Clean Air Markets Division

cc: Dan Mahar, Northwest Air Pollution Authority, Washington
Dan Meyer, EPA Region X
Travis Johnson, CAMD
Kenon Smith, CAMD

[6] If it is determined that Encogen became subject to the ARP before November 1, 1999 and thus subject to the ARP allowance-holding requirements before February 1, 2000 (i.e., starting on some date in January 2000), then Encogen must apply the alternative substitute data calculation methodology approved here to the additional time period.