IN THE UNITED STATES DISTRICT COURT

FOR THE WESTERN DISTRICT OF WISCONSIN

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UNITED STATES OF AMERICA,

Plaintiff,

OPINION AND ORDER

00-C-0409-C

v.

MURPHY OIL USA, INC.,

Defendant.

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Plaintiff United States of America is suing defendant Murphy Oil USA, Inc. for alleged violations of environmental laws. Primarily, plaintiff alleges that defendant made major modifications to the sulfur recovery unit at its Superior, Wisconsin oil refinery without obtaining permits required under the Clean Air Act, 42 U.S.C. §§ 7401-7671q, without complying with performance standards applicable to the work and without employing the best available control technology. Defendant denies any failure to comply. It maintains that all of the improvements it made to its sulfur recovery unit were motivated by the need to meet state and federal air quality standards and were undertaken in close cooperation with the Wisconsin Department of Natural Resources, the authority responsible for issuing Clean Air Act permits in Wisconsin. Plaintiff does not dispute defendant's assertion that its projects were intended to improve its pollution control efficiency or that defendant followed the state's directives. Rather, plaintiff contends that defendant avoided compliance by withholding critical information from regulators that would have indicated that its proposed modifications would trigger application of various regulations and permit requirements. Plaintiff is suing for the withholding of the information as well as for the penalties and injunctive relief available upon a showing that an operator modified a regulated pollution source without compliance with the provisions of the act. Besides the alleged Clean Air Act violations, plaintiff has alleged that certain acts and omissions of defendant violated various provisions of the Clean Water Act, 33 U.S.C. §§ 1251-1387, and the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6021-6039e.

Before trial, the case was pared down slightly as a result of motions for partial summary judgment that led to findings in favor of plaintiff on some of its claims and in favor of defendant on one of its affirmative defenses, see Opin. and Order entered on May 18, 2001. It was trimmed further after plaintiff withdrew some of the 24 claims it had alleged originally, including all of the claims it had raised under the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. §§ 6991-6991h. Trial to the court proceeded on the remaining claims and affirmative defenses June 7-16, 2001.

The bulk of trial time was devoted to plaintiff's four remaining Clean Air Act claims.

The first is that defendant made major modifications to the sulfur recovery unit at its oil refinery in 1987-88 and in 1991-93 and that each project resulted in a net emissions increase of sulfur dioxide of more than 40 tons a year, obligating defendant to obtain a Prevention of Significant Deterioration permit. Plaintiff seeks an order prohibiting defendant from continuing to operate the sulfur recovery unit without obtaining a Prevention of Significant Deterioration permit and a civil penalty for making modifications to the sulfur recovery unit without the required permit.

In claim two, plaintiff seeks to enjoin defendant from operating its sulfur recovery unit without using best available control technology and to collect a civil penalty from defendant for making modifications to the unit without complying with this requirement of the Clean Air Act.

Plaintiff's third claim is that defendant did not provide all the relevant information plaintiff needed in order to determine whether the modifications defendant proposed to make in 1993 (routing its No. 2 distillate unifier into the sulfur recovery unit) would result in a significant increase in emissions from the sulfur recovery unit. Defendant admits that it withheld certain consultant reports but denies that anything in these reports was relevant, in the sense that it would have affected the permitting authority's decision making. If defendant is correct, plaintiff will be prevented by operation of the applicable statute of limitations, 28 U.S.C. § 2462, from pursuing its demand for penalties against defendant on the first and second claim as they relate to the modifications that defendant made to the distillate unifier in 1992-93 because I have held that the statute of limitations may be tolled only if plaintiff proves that defendant made affirmative efforts to withhold relevant documents, that is, that defendant withheld documents knowingly and intentionally. (Plaintiff does not argue that defendant withheld relevant information in connection with the modifications it made before 1992; it concedes that the statute of limitations bars it from seeking penalties against defendant for making those modifications without obtaining a Prevention of Significant Deterioration permit.)

Plaintiff's third claim involves information provided by engineering consultants defendant hired at various times to suggest ways of making the sulfur recovery plant operate more efficiently. The information at issue includes the following: 1) reports prepared in 1987 by Sulfur Operations Support, a consulting firm, that include the consultants' statement about the efficiency of the sulfur recovery unit before construction began in 1987, projected rates of efficiency after construction and references to the need for a larger combustion chamber; 2) reports from a firm known as Western Research that describe four stack tests and a material balance or performance test the firm conducted during 1989; and 3) reports from Becker, Losier & Associates that were prepared in 1989 and 1992 and discuss estimated recovery efficiency. Plaintiff contends that in addition to the consultants' reports, defendant should have given the permitting authority information relating to a questionable stack test. The withholding of information claim can be reduced to two questions: whether the reports contain information that would have affected the permitting authority's decision making and whether defendant would have had reason to know that it should have submitted the reports.

Plaintiff's fourth claim is based on its contention that since the completion of defendant's modifications in the early 1990's, the sulfur recovery unit has had the capacity to process more than 20 long tons a day of sulfur, that is, the unit's "throughput" capacity has exceeded 20 long tons a day of sulfur. If plaintiff is correct, the unit has been subject to New Source Performance Standards, which would require defendant both to limit its sulfur dioxide emission concentration from the sulfur recovery unit to the standard set out in 40 C.F.R. § 60.104(a)(2) and to install an emissions control system to limit the sulfur dioxide concentration. Defendant denies that its sulfur recovery unit can process more than 20 long tons a day of sulfur and contends that even if the unit has done so on a few occasions, it was never designed to do so and cannot do so safely without risk of harm to its component parts. Additionally, defendant denies that the 20 long tons a day limit is measured by input (throughput) and not by output (production).

I conclude that defendant failed to submit to the Department of Natural Resources the information relevant to the department's determination whether defendant's proposed modifications of the No. 2 distillate unifier would require a Prevention of Significant

Deterioration permit, compliance with New Source Performance Standards and use of best available control technology. If defendant had submitted the information, the department would have known that defendant did not qualify for a synthetic minor permit but needed a Prevention of Significant Deterioration permit and was required to comply with the New Source Performance Standards and best available technology. I conclude also that defendant knew that the withheld information would have been relevant to the department's permitting decision and should have been disclosed. The failure to disclose this information tolls the running of the statute of the limitations, 28 U.S.C. § 2462. I conclude also that defendant's sulfur recovery unit was designed to process at least 20 long tons a day of sulfur.

I conclude that plaintiff is entitled to judgment on its claims ten, eleven, twelve and thirteen, brought under the Clean Water Act, but that it has failed to prove its Resource Conservation and Recovery Act claim. A determination of the relief to which plaintiff is entitled will be made after the second phase of trial, which will be devoted to penalties and injunctive relief.

From the evidence adduced at trial, I make the following findings of fact.

## FACTS

## I. CLEAN AIR ACT

### A. Background

Plaintiff United States of America brings this suit on behalf of the United States Environmental Protection Agency. (As in the earlier order, I will use "plaintiff" to refer to the EPA.) At all relevant times, the United States has delegated to the state of Wisconsin the authority to issue Prevention of Significant Deterioration permits and to determine the applicability of New Source Performance Standards.

Defendant is a Delaware corporation that operates an oil refinery in Superior, Wisconsin. It takes crude oil from the Lakehead Pipeline and refines it into several petroleum derivatives, including at least six types of crude oil with varying sulfur content.

Although defendant's refinery includes many different processes, the only one at issue for the purpose of the alleged Clean Air Act violations is the sulfur recovery unit, which is designed to treat the hydrogen sulfide that is a byproduct of the refinery process and arrives at the sulfur recovery unit in pipes from the various processing units throughout the refinery. Amine acid gas and sour water stripper gas are fed through separate piping into the sulfur recovery unit, which converts the hydrogen sulfide in the gases into elemental sulfur and sulfur dioxide through a process known as the Claus reaction. (Before defendant made the 1991-93 modifications to the sulfur recovery unit, it did not route the sour water stripper gas through the sulfur recovery unit but sent it directly to the incinerator without treatment.) Typically, two-stage Claus burners convert 90 to 95% of the hydrogen sulfur in waste gases into elemental sulfur. They do so by passing the gases over a catalyst at an elevated temperature and pressure in the presence of hydrogen. The resulting hydrogen sulfide is then sent to the sulfur recovery unit for conversion into elemental sulfur, with the unconverted hydrogen sulfide going to a tail gas incinerator that combusts the hydrogen sulfide in the presence of oxygen to form sulfur dioxide. The elemental sulfur is routed to a sulfur pit as a product and sold commercially.

B. Defendant's Sulfur Recovery Unit - 1987-88 Modifications

Sulfur recovery unit operators have a significant incentive to achieve highly efficient recoveries of elemental sulfur not only to increase the income from the sale of the product but to avoid Clean Air Act penalties for excessive pollution emission. Despite this incentive, defendant had difficulty operating its sulfur recovery unit from the time it was purchased in 1973 through the early 1990s. The unit is a small one built originally for a gas plant and not for an oil refinery. Up through the 1980s, it was often off line and had frequent mechanical failures. In 1986-87, defendant employed Sulfur Operations Support to analyze the unit's problems and provide suggestions for design changes. The firm provided defendant with a number of reports in letter form. In a letter that appears to have been sent in the fall of 1986 (Exh. #436), Sulfur Operations advised defendant that the sulfur recovery plant had an 85 to 90% recovery rate in the conditions under which it operated but defendant could expect to achieve a 91-93% rate if it could bring the plant's conditions up to standard. In a January 20, 1987 letter (Exh. #431 at 7), Sulfur Operations projected various recovery rates under different conditions, all of which would produce recovery rates of 89.5% or higher. In a February 13, 1987 letter (Exh. #434 at 4), the firm noted that the existing combustion chamber was too small. In an April 10, 1987 letter, it calculated the rate of sulfur recovery from each of two design proposals it had made, showing the lower rate as 91.5% and the higher as 92.3%. In June 1987, defendant added a tail gas analyzer to the sulfur recovery unit.

In a February 1988 response to a notice of violation of the state's Statewide Sulfur Dioxide Rule, defendant advised the Department of Natural Resources that the modifications it would be making to the sulfur recovery unit would enable it to operate the unit in July 1988 and to demonstrate full compliance with the proposed alternate emissions limits no later than September 1988. When the sulfur recovery unit and associated amine system were not operating, sour gases bypassed the sulfur recovery unit and were burned directly without pollution control, causing an increase in sulfur dioxide emissions. In 1988, 1990 and 1991, there were times that defendant's emissions exceeded the legal limits under the Wisconsin Administrative Code.

On April 8, 1988, defendant met with Department of Natural Resources staff to present a proposal and schedule to undertake various enhancements to the sulfur recovery unit to reduce emissions and bring the refinery into compliance with state sulfur dioxide rules. The department found the proposal acceptable. The changes to the sulfur recovery unit that defendant was planning to make included upgrading the primary burner, replacing the catalyst, installing a new and larger combustion chamber, adding an acid gas knock-out drum and a tail gas analyzer, a hydrocarbon coalescer in the upstream amine unit and a distributed control system. The changes it told the department about did not include increasing the size of the new combustion chamber, although it did say that the new chamber would provide increased residence time. Defendant expected the changes to increase the reliability of the unit and improve its sulfur recovery efficiency. Before defendant made these modifications to the sulfur recovery unit, it never applied for a permit for them from the Department of Natural Resources, which administers the Clean Air Act in Wisconsin, or asked for an exemption from permitting requirements.

The capacity of a sulfur recovery unit to process gas streams and derive elemental sulfur is measured in long tons of sulfur per day. According to reports filed with the Bureau of Mines, defendant was producing an average of 142.5 long tons a month of sulfur during the two years preceding the start of the 1987-1988 modifications, that is, two years before the installation of the tail gas analyzer in June 1987.

In an October 17, 1986 letter to the Department of Natural Resources, James Gesick, manager of the Superior refinery, reported the results of two 1986 stack tests showing a 75-80% sulfur recovery efficiency. Exh. #268. In September 1988, the department began enforcing a 393 pound an hour limit of sulfur emissions. Before June 1987, defendant's air emissions inventory showed an average recovery rate of 76%.

Shortly before the start of trial in this case, Steven Dunn, an engineer with the Department of Natural Resources, made a nunc pro tunc calculation of defendant's actual emissions during the two years preceding the installation of the tail gas analyzer using an 80% recovery rate and the reported monthly average sulfur production rate of 142.5 long tons a month. Dunn derived an actual emission rate of 957.6 tons of sulfur a year. Using the 76% figure shown by the air emissions inventory, he derived an actual annual emissions rate of 1,210. He calculated the sulfur recovery unit's potential to emit after the planned changes were made as being 393 pounds an hour because of the state emissions limit that went into effect in 1988 and arrived at an annual rate of emissions of 1721, or an increase of 763.7 tons over the actual emissions calculated at an 80% rate and 511 tons over the 1,210 tons produced by using a 76% recovery rate. (In responses to requests for admission defendant filed on February 12, 2001, it agreed that no applicable federal emissions limitation was in effect in 1988 and that the state was enforcing a 393 pound an hour restriction.)

In a July 7, 1986 memorandum from plaintiff's Director of the Office of Air Quality Planning and Standards, the director stated that exemptions available under the New Source Performance Standards that applied to systems or devices with the primary function of the reduction of air pollution did not apply automatically under the Prevention of Significant Deterioration program. Exh. #3039. The director concluded by saying that he was withdrawing an earlier memorandum on the topic (Exh. #3013) in which he had held that for Prevention of Significant Deterioration purposes, the term modification would include all the exemptions included in the New Source Performance Standards regulations.

In 1989, defendant retained the Western Research consulting firm to conduct a comprehensive full performance test on the sulfur recovery unit, which continued to have problems that required shut downs and produced excessive emissions of sulfur dioxide. In a letter dated September 1, 1989, the firm wrote Mark Miller, process engineer for the Superior refinery, confirming its agreement to consult and adding its understanding that defendant's goals were "a complete performance test of the sulfur recovery unit, an evaluation of current plant operating practices, and procedures and sulfur plant capability studies for possible future addition of distillate hydrotreating to the refinery." Exh. #426. On September 19, 1989 and from October 24-26, 1989, Western Research conducted a full performance test of the sulfur recovery unit to evaluate its recovery performance under normal operating conditions and to help the refinery meet licensed emission guidelines during the compliance stack test scheduled for late October. Western Research reported a measured conversion efficiency from its October test of 96.04% of the total inlet sulfur, which it noted was consistent with the rated conversion efficiencies of 95.4% for the unit and which "displayed a large improvement over the September results [when the] estimated conversion efficiencies [were] between 93.3 percent and 95.1 percent." Exh. #427 at Bates No. MOII00495. The firm attributed the increased efficiency to operational changes carried out before the October test, id., but noted that during its October test, the unit was operating without the Air Demand Analyzer on line, which resulted in losses because of off-ratio conditions. Id. at Bates No. MOII00504. (The analyzer monitors the ratio of hydrogen sulfide to sulfur dioxide and adjusts the air flow automatically to keep the ratio at 2 to 1 or slightly higher for maximum efficiency of sulfur recovery. When the analyzer is not working, the operators must monitor the ratios and make the corresponding adjustments manually.) In addition, the final condenser coalescer was operating at a higher than desired temperature, leading to sulfur vapor in the tail gas.

Also, Western Research reported that during the September testing the sulfur recovery unit had demonstrated poor conversion efficiencies that Western Research attributed to high excess air values and possible diethylamine leakage into the condensers, possibly contaminating the converter beds.

The performance tests included a material balance (an analysis of the pertinent gas stream compositions, measurement of key process stream flows and the monitoring of the process temperatures and pressures). Id. at Bates No. MOII00499. A material balance can provide data acceptable for determining baseline emissions for permitting purposes. As part of the report, Western Research had a graph of net recovery efficiency (percent) and modified-Claus process practicable capability. Dotted lines and the words "Murphy Oil - Superior SRU" showed a net recovery efficiency for defendant's sulfur recovery unit at above 96%. Id. at Bates No. MOII00509 (reproduced at Appendix A). This graph was submitted to the Department of Natural Resources as part of the No. 2 distillate unifier application, independently of the Western Research report and with the words "Murphy Oil - Superior SRU" deleted. Defendant did not supply the department with the graph in the form it was prepared by Western Research. It did not turn over any other portion of the Western Research report in 1992 or 1993 or even in 1999, when plaintiff was investigating this matter, although it turned over other previously withheld consultant reports in June 1999 and had the Western Research report in its possession before then. The report was discovered in December 1999. In addition, the Western Research report included a material balance of the sulfur recovery unit, summarizing the components going into and out of the unit.

Also in 1989, defendant retained Becker, Losier & Associates to propose possible improvements to the sulfur recovery unit. In a report dated September 28, 1989, Walter Losier noted the problems with the September 13, 1989 stack test that made the results unreliable and made recommendations to defendant for changes to solve the problems.

Plaintiff's policy is to give independent treatment to "major stationary sources" within another "major stationary source" for Prevention of Significant Deterioration purposes. Using a "nested facility" concept, it does not allow operators to hide a major stationary source within another one.

### C. 1991-1993 Modifications

Defendant knew that it would have to increase the capacity of the sulfur recovery unit to produce low sulfur diesel fuel to conform with new environmental regulations. As of 1990, its unit's design capacity was 15.1 long tons a day, Exh. #460; defendant wanted to be able to process an extra four long tons a day. Defendant retained Becker, Losier again in 1990, this time to study possible improvements in the unit to increase its processing capacity. In turn, Becker, Losier retained E&L Engineering to prepare a comparison study of the existing design of the sulfur recovery unit and a future design of revisions that would add a new 9.0 pound per square inch gauge blower and deeper sulfur seal legs, allowing an increase in acid gas flow equal to 16.0 long tons of sulfur a day. (Sulfur seal legs are devices used to balance the pressure of the process to the atmospheric pressure outside.) In April 1990, defendant asked E&L to add a new design study "to determine the unit capacity bottlenecks when additional acid gas is brought into the unit." Exh. #282.

On May 21, 1990, David Petty, an employee of defendant, wrote to the Department of Natural Resources, asking whether two proposed alternatives for modification of the existing sulfur recovery unit would trigger application of the New Source Performance Standards. He told the department that one of the options defendant was considering was simply "to replace the existing heat recovery unit and sulfur condenser with updated equipment of the same design but with different metallurgy." Exh. #284 at 2. Petty described the second option, which was to separate the amine and sulfur recovery systems, using the steam generated from the cooling water on a new heat recovery unit and sulfur condenser to heat the amine in a new, separate reboiler. Id. Petty noted that the sulfur recovery unit had a nominal design capacity of 14 long tons a day and that ordinarily, the New Source Performance Standards do not address Claus units smaller than 20 long tons a day. He stated that neither of the options defendant was considering would "increase throughput capacity or emissions and that neither would constitute a reconstruction (because the anticipated cost of less than $1.5 million would not exceed 50% of the projected replacement price of $3.5 to 4 million). Id. Petty did not tell the department that in fact, defendant was considering two designs that showed an increased gas flow rate of 15.1 long tons a day of sulfur in the feed gas with a new 8.0 pounds per square inch blower and an increased sulfur feed rate of 19.7 long tons a day with an 11 pounds per square inch blower, increased heat exchange surface area, 20 foot deep seals and larger gas pipes, as shown in Becker, Losier's May 7, 1990 memorandum, Exh. #460.

The department advised defendant that neither of the alternative plans for modification described by Petty would trigger New Source Performance Standards or Prevention of Significant Deterioration requirements or require a new source air pollution control permit. Exh. #135. It asked defendant to submit a plan and schedule for "design, construction and operation of the unit" by July 30, 1990. Id.

Sometime before July 26, 1990, defendant asked E&L to base a design on two new blowers it had purchased: one of 11.5 pounds per square inch gauge and the other of 9.0 pounds. Defendant asked E&L to provide 17 to 18 foot sulfur seal legs to accommodate the larger blowers. On July 30, 1990, James Gesick, manager of the refinery, wrote to the Department of Natural Resources, saying that defendant had agreed to undertake the 1991 sulfur recovery unit improvements and that it had elected the second option, which involved separating the amine and sulfur recovery systems. (Gesick listed the two alternatives as 1) "Replace the existing heat recovery unit and sulfur condenser on a one-for-one basis with the same equipment"; and 2) "Separate the amine and sulfur recovery systems and provide a separate new reboiler." Exh. #3158.) Gesick provided a schedule for completion and noted that defendant was undertaking the work on the understanding that it would not trigger either New Source Performance Standards or Prevention of Significant Deterioration requirements. Id. Defendant never advised the Department of Natural Resources of the exact nature of the actual modifications it was making. It did not tell the department that it was installing new and more powerful blowers that would increase the unit's capacity. It never submitted the reports from Becker, Losier & Associates with the reports from Becker, Losier's subcontractor, E&L, showing the scope of the planned changes and the installation of the larger blowers, or the May 15, 1992 letter from the firm advising defendant that its sulfur recovery unit was operating at a 95 to 96% recovery rate and that this represented an improvement over the 90% to 92% efficiency rate of the unit before the hot gas by-pass was eliminated. Had defendant submitted these materials, they would have affected the decision making of the department.

During a September 21, 1990 conference on an unrelated matter, defendant told plaintiff that it was constructing a modification to its sulfur recovery unit under the guidance of the Department of Natural Resources and that the project was not subject to New Source Performance Standards. Defendant sent plaintiff copies of the 1990 correspondence between it and the department concerning the modifications to be made to the sulfur recovery unit. (As noted, this correspondence made no reference to defendant's specific changes and its plan to add the more powerful blowers and accompanying sulfur seal legs.) Plaintiff gave preliminary approval to the Department of Natural Resources' position that defendant's construction of its second option was not subject to New Source Performance Standards and did not require construction or operation permits. Defendant began construction and provided both plaintiff and the Department of Natural Resources with periodic progress reports.

Defendant modified the sulfur recovery unit in 1991 by replacing the 9 foot sulfur seal legs with deeper 18 foot legs; installing a new and larger sulfur pit; installing two new air combustion blowers, one of 9.0 pounds per square inch and one of 11.5 pounds per square inch; replacing and increasing the heat exchange surface of the waste heat boiler; and enlarging the condenser surface area on the sulfur recovery area.

As part of the 1991 project, defendant re-routed the sour gas generated by the sour water stripper to the sulfur recovery unit for pollution control purposes. Defendant never advised anyone in the permitting section of the Department of Natural Resources that it was re-routing the sour water stripper gas and thereby increasing the feed to the sulfur recovery unit. In a single-spaced, 3½ page letter dated November 2, 1990, and written to Steven Dunn, a department engineer not working in the permitting section, Eder & Associates stated on defendant's behalf that "[t]he waste gas incinerator stack number 15G-H1 does not comply with down wash minimization criteria. Emissions from this stack have not been tested but this source is being eliminated and emissions are being routed to the sulfur plant." Exh. #3178 at 1. Eder made no other mention of the re-routing in the November 1990 letter or in any other communication to the department. In April 1992, nearly two years after defendant had first sought approval of what was to be its 1991 modification project, Dan Rosenthal, the regional Department of Natural Resources compliance engineer, made an inspection visit to the refinery and was told about the re-routing.

In April 1992, defendant sought regulatory guidance from Rosenthal for a project involving improvements to defendant's No. 2 distillate unifier that would enable defendant to produce diesel fuel that met the new sulfur limits of the Clean Air Act. Defendant wanted to increase the desulfurization capability of its unifier by installing a larger reactor. Rosenthal told defendant that the incremental feed to the sulfur recovery unit from the unifier would require an air permit application and that the project would be subject to Prevention of Significant Deterioration requirements, including air dispersion modeling and best available control technology analysis. Earlier, on March 19, 1992, Tom Graney, manager of engineering at the refinery, had sent a memorandum to refinery manager Ron Anderson asking about defendant's obligations to the Department of Natural Resources in connection with the distillate unifier revamp. Graney wrote that the project would "increase plant SO2 emissions due to the generation of additional feed to the sulfur recovery unit" of about 171 pounds an hour, which would produce an additional 816 pounds a day of sulfur dioxide discharged from the sulfur recovery unit incinerator stack, assuming a 90% recovery. Exh. #358.

Defendant was eager to get the unifier project completed so that it would be able to start producing low sulfur diesel fuel by August 1, 1993. In a letter written to the department on July 6, 1992, Mark Miller, defendant's process engineer, stated that the distillate unifier project would increase the hydrogen sulfide feed rate to the sulfur recovery unit and that there would be a concomitant increase in sulfur dioxide emissions. Exh. #3291 at 1. He assured the department that the increased feed rate would be well within the design capacity of the sulfur recovery unit and illustrated the point with a table showing the then current daily maximum feed as 14 long tons a day and the estimated design maximum as 19 long tons. Id. at 1-2. He added that in his opinion the project was exempt as a "specified change in operation" because changes in sulfur removal at the No. 2 distillate unifier resulted in an increase in sulfur production that did not exceed the operating capacity of the sulfur recovery unit.

On July 14, 1992, defendant submitted a permit application seeking authorization to modify its No. 2 distillate unifier. It said nothing in the application about the fact it had increased the maximum sulfur input capacity of the sulfur recovery unit as part of the 1991 modifications it had made. In response to a request for guidance, plaintiff told the Department of Natural Resources that defendant would need a Prevention of Significant Deterioration permit unless it were to "net out" or restrict emissions through a "synthetic minor permit." At the request of the Department of Natural Resources, defendant amended its application to obtain a "synthetic minor permit," which is a means of avoiding the need for a Prevention of Significant Deterioration permit. To obtain such a permit, the applicant must meet certain criteria and agree to restrict emissions.

As part of the permit application, defendant had to show what its actual sulfur dioxide emissions were before construction began on the unifier and what the potential emissions would be after the project's completion. Defendant chose to use a baseline period of August 1, 1989 to August 1, 1991, and a baseline recovery efficiency of 90%, taken from a stack test it had conducted on October 31, 1989.

The Department of Natural Resources decided that the 1989-91 period should be changed to the 24-month period immediately preceding the No. 2 distillate unifier project. Consequently, defendant changed the baseline period to July 1990 to August 1992. This change resulted in lower pre-construction sulfur dioxide emission levels when defendant showed a 93% sulfur recovery efficiency for 10 of the 24 months. With lower pre-construction baseline emissions and the same post-construction emissions, the potential increase in emissions triggered Prevention of Significant Deterioration requirements.

On September 17, 1992, refinery manager Ron Anderson wrote the Department of Natural Resources, revising the No. 2 distillate unifier permit application and specifically revising the baseline recovery efficiency estimates by claiming a pre-project recovery efficiency of 86% for the 14-month time period before the 1991 sulfur recovery unit modification (July 1990 through August 1991), rather than the 90% recovery efficiency it had submitted for the entire time period of August 1, 1989 through August 1, 1991 in its original application for the distillate unifier work. Exh. #313. To achieve the 86% efficiency rate, defendant averaged the results of two stack tests, the October 31, 1989 test that had been observed by the department and a September 13, 1989 stack test that had not been observed. According to defendant, the September 13, 1989 stack test showed an 82% efficiency recovery rate. Defendant did not tell the department that Western Research had conducted stack tests on September 19, 1989 and again on October 24-26, 1989, that the September 19 testing produced estimated overall conversion efficiencies ranging from 93.3% to 95.1%, that the October 24-26 tests showed a measured conversion efficiency of 96.04% or that during the unobserved September 13 test, the heat recovery unit tubes had been leaking diethylamine into the Claus side of the process. Had defendant given the Western Research report to the department, it would have affected the department's decision on the permit application. Defendant urged the use of the September 13 test despite the fact that Mark Miller, defendant's process engineer, had written to Tom Graney on May 29, 1992, saying that four performance tests had been run but that in his opinion, the sulfur recovery unit had been running properly only during the October 13, 1989 test. He had advised Graney that during the September 13 test, diethylamine had been leaking into the Claus side of the process and he had recommended bringing Western research back to run another test. Exh. # 361.

In the September 17 letter, Anderson listed the total sulfur shipped out of the plant each month for the two year period as the basis for setting baseline emissions. Exh. #313. In a September 24, 1992 letter from Paul Yeung, permitting examiner, to Dan Rosenthal, the department's compliance engineer in the Superior area, Exh. #204, Yeung wrote, "Both Murphy and the DNR have agreed that the basis for setting the baseline emission amount will be to use the total sulfur shipped out of the plant."

Rosenthal opposed defendant's efforts to use an 86% efficiency rate for any portion of the pre-construction period. In his opinion, the 82% figure was unreliable because it had been obtained from a stack test that the department had not observed and because his reading had convinced him that the normal range of recovery rates for sulfur recovery units is closer to the high 90s. Rosenthal argued his position vigorously with the department's permitting authorities, but was unsuccessful in persuading them to use a higher recovery rate.

In November 1992, the Department of Natural Resources issued defendant Air Pemit No. 92-POY, after determining that the modification involving the No. 2 distillate unifier would be exempt from Prevention of Significant Deterioration review because defendant had agreed to abide by synthetic minor permit limitations that restricted emissions from the refinery to levels below Prevention of Significant Deterioration applicability thresholds. The department concluded that the proposed change would be minor because the increase of sulfur dioxide emissions would be less than 40 tons a year.

Also in November 1992, Paul Yeung responded to a comment on defendant's permit application from two residents of Superior. Among other things, he wrote that defendant's "allowable sulfur dioxide emissions will be, for all practical purposes, the same as the sulfur dioxide emissions that [defendant] is currently emitting." Exh. #154.

During the 30-day appeal period following issuance of the permit, plaintiff's inspectors toured defendant's refinery to inspect air pollution sources and determine compliance with all applicable air rules. Although this was not a full-fledged inspection but primarily an opportunity to become familiar with the air pollution sources in the region, plaintiff's staff discussed the sulfur recovery unit, the No. 2 distillate unifier project and the air permit. Plaintiff never filed an appeal of the permit or registered any objection to it.

During 1992, defendant constructed a new amine tower for separating hydrogen and hydrogen sulfide at the distillate unifier. Between 1992 and 1993, defendant increased the reactor size of the distillate unifier.

Lee Vail is Manager of Environmental Affairs for defendant. He has a Ph.D. in environmental engineering. In 1999, when plaintiff and the Department of Natural Resources were investigating this matter, Vail turned over the Sulfur Operations Support reports and two reports from Becker, Losier & Associates, without the reports by E&L. He did not turn over the Western Research report, although he had it in his possession from before June 1989, if not earlier. In correspondence with the department before the department discovered the Western Research report, Vail maintained that the department lacked any evidence to show that defendant had used an inaccurate stack test result as a basis for computing its pre-construction emissions.

D. Capacity of Sulfur Recovery Unit

In a letter dated September 11, 1990, Mark Miller wrote to McGill Environmental Systems, Inc., seeking information about the McGill reaction furnace installed in defendant's sulfur recovery unit. Specifically, Miller wanted to know how the burner pressure drop would increase when the feed flow rate to the sulfur recovery unit was increased. Miller enclosed a table showing projected rates for its unit. Using the numbers in the table, Miller calculated the sulfur feed rate would be 22.7 long tons a day. Exh. 750. Miller believed that before 1991, the sulfur recovery unit had a maximum sulfur input rate of more than 15 long tons a day; he projected a six or seven long ton a day increase with the changes to be made in 1991-1993.

In a letter dated December 22, 1995, Exh. #320, David Podratz, defendant's manager of technical services, wrote to TPA, Inc., a consulting firm, about a new tail gas treating process. He informed TPA that

> We have operated the existing [sulfur recovery] unit with sulfur production of up to 20 LTPD at recoveries of about 94%. I believe the ultimate capacity of the existing unit is about 22 LTPD. The new tail gas treating process should be designed so as not to limit our SRU capacity with recoveries of greater than 98%.

Defendant is required to provide to the United States Department of the Interior, United States Geological Survey information about monthly sulfur production, shipment and disposition. When sulfur production data for October 1996 are combined with defendant's continuous emissions monitor data, the calculations show that the average sulfur input into the sulfur recovery unit for that month exceeded 20.27 long tons per day. Continuous emission monitoring data from 1994 through September 1998 indicate that there were 210 days with an input greater than 20 long days per ton of sulfur into the sulfur recovery unit, assuming a 95% recovery rate. (Assuming a 94% recovery rate, there were 14 days during the same time period when the input exceeded 20 long tons a day.)

Daily sulfur pit stick production data for 1991 through 1998 showed that the sulfur recovery unit produced over 20 long tons per day of sulfur on 148 days from 1991 through approximately September 1998. Sulfur pit stick measurements are prone to error; defendant measures the sulfur pit with nothing more sophisticated than a measurement tape with a bullet weight attached to a swivel at one end. The person doing the measurement cannot tell whether the weight is reaching the bottom of the pit and whether it is still upright or lying on its side because of the opacity of the sulfur. This uncertainty makes it easy to make a six inch mistake in measurement. However, the error can be either plus or minus actual sulfur levels. If the weight is lying on its side, the measurement will overstate the sulfur level; if, for some reason, the weight does not sink to the bottom of the pit, it will understate the sulfur level. Defendant relied on stick pit measurements in estimating its sulfur recovery efficiency rate for the stack tests performed on September 13, 1989 and October 31, 1989. Exh. #204.

With the changes made to the sulfur recovery unit in 1991-1993, the capacity of the unit to process sulfur increased to more than 20 long tons a day. The larger blowers and seal legs allowed the unit to be operated at higher pressure (up to about 11.5 psig), which means that the operator could "push" more sulfur through the sulfur recovery unit and increase the capacity. The lesser of the two blowers showed a capacity of 17.5 long tons a day; the larger showed a capacity of 21.7 long tons a day.

Brimstone Engineering Services did a performance evaluation of the sulfur recovery unit in July 1988. Included in its report was pressure drop information for the unit that both defendant's expert, John Bourdon, and plaintiff's expert, Paul d'Haêne, relied upon in their calculations of maximum throughput capacity of the unit. Pressure drop information is necessary for knowing how much driving force is needed to push a certain amount of air through the piping system, given a known reaction furnace pressure. Maximum throughput in a sulfur recovery unit occurs at the point at which the pressure drop equals the available pressure on feed gases and on the air.

The Brimstone pressure drop information confirms that when the sour water gas feed is 0.6 long tons a day and the remainder is amine acid gas, the capacity of the sulfur recovery unit is up to 22.8 long tons a day if the control valves are wide open and not slightly pinched as they were in the Brimstone performance test. When the percentage of sour water gas feed increases to 1 to 1.3 long tons a day of sulfur, the sulfur recovery unit can process 21.7 long tons a day.

Defendant's sulfur recovery unit has two control valves. The 6 inch valve does the bulk of the work and keeps the air coming in at the amount required by the assumed percentage of hydrogen sulfide in the feed. The smaller 2 inch valve acts as the trim controller, adjusting air flow in response to the air demand analyzer so as to maintain the optimum two parts hydrogen sulfide to one part sulfur dioxide.

When plaintiff published the new source performance standards of subpart J of 40 C.F.R. part 60 in 43 Fed. Reg. 10,868 (Mar. 15, 1978), it said that the standards of performance for new stationary sources referred to Claus sulfur recovery units that had sulfur *production* capacity in excess of 20 long tons a day. In the New Source Performance Standards subpart J, amended on October 25, 1979, plaintiff wrote that a sulfur recovery unit was subject to the standards if it had a *processing capacity* of more than 20 long tons a day. 44 Fed. Reg. 61,542 (Oct. 25, 1979).

On October 22, 1992, John Rasnic, plaintiff's Director, Stationary Source Compliance Division, Office of Air Quality and Standards, issued a memorandum in which he wrote,

This memorandum amends the June clarification to make the 20 [long tons per day]

> exemption under [new source performance standards] Subpart J more practicable,. The June 2, 1992 memorandum stated that the [long tons per day] applicability exemption refers to the amount of sulfur which a Claus plant is designed to produce. A definition of [long tons per day] based upon output would allow exemptions for inefficient, and thus low sulfur-producing facilities. Applicability based upon output would also apply differently to similar units depending on performance, and penalize efficient control devices with high sulfur recovery. A definition based upon feed rate and amount of sulfur input is more logical than a definition based upon the output.
>
> Therefore, long tons per day means the design capacity of a Claus sulfur recovery plant based upon feed rate and content of hydrogen sulfide (expressed as sulfur) in the acid gas stream.

Exh. #120.

In a memorandum dated July 7, 1986, plaintiff's Director of the Office of Air Quality Planning and Standards stated that exemptions available under the New Source Performance Standards to systems or devices with the primary function of air pollution did not apply automatically under the Prevention of Significant Deterioration program. Exh. #3039. The director concluded by saying that the earlier memorandum on the topic (Exh. #3013) had been withdrawn.

## II. CLEAN WATER ACT

### A. Clean Water Act: Claims Ten, Eleven, Twelve and Thirteen

In May and June 1998, Daren Vanlerberghe, an environmental engineer with plaintiff's National Enforcement Investigations Center, inspected defendant's refinery. At the time, defendant gave Vanlerberghe a copy of its Spill Prevention Control and Countermeasure Plan that had been certified on April 4, 1996, with amendments dated November 1996 and June 1997.

1. Claim Ten

Slop oil tanks S-1 and S-2 began operating in 1994 and 1995 respectively. When tanks S-1 and S-2 began operation, they had no diked secondary containment area. Defendant had a 42-gallon spill at slop oil tank S-1 on December 8, 1994, and a 50-gallon spill at slop oil tank S-2 on January 4, 1995. In May 1995, defendant added slop oil tanks S-1 and S-2 to its Spill Prevention Control and Countermeasure Plan as potential spill sources. The plan listed the capacity of each slop oil tank as 572 barrels and the capacity of their diked area as zero. In March 1996, defendant amended its Spill Prevention Control and Countermeasure Plan to provide for installation of a sufficient diked secondary containment area for slop oil tanks S-1 and S-2. Defendant's amended plan stated, "Presently, the Slop Oil Tanks (tank numbers S-1 and S-2) do not have diked secondary containment areas. Dikes will be installed in the future to provide adequate secondary containment." This amendment was repeated in defendant's plan of June 1997.

As early as January 1997, the Wisconsin Department of Natural Resources notified defendant of the need for remedial action at slop oil tanks S-1 and S-2. Defendant did not propose the installation of a concrete containment area to the department until November 24, 1998. The department's employee who is overseeing a spill site can recommend that the site be closed after he is satisfied with the cleanup of the site. In a letter dated May 29, 1998 to defendant's process engineer, Mark Miller, departmental employee James Hosch wrote, "Once a completed site investigation report is submitted, Murphy can propose what levels of contaminants can remain at the site, what soil can be left in place until access is gained, site specific residual containment levels, and engineering and institutional controls." In response to defendant's request that the department close its investigation of the site surrounding slop oil tanks S-1 and S-2, Hosch sent an e-mail to defendant's Manager of Environmental and Process Safety, Liz Lundmark, to which he attached a memorandum in which he wrote, "Murphy proposes to [] install a concrete and a 60-mil HPDE membrane liner at the site to prevent future spills from infiltrating soil and to prevent precipitation from migrating into soil. **Murphy needs approval before the end of August to install this system, if they are to go ahead this year.**" (Emphasis in original.) The department did not ask or order defendant to postpone installation of the concrete containment area during the investigation. Defendant needed the department's approval for closure of the site but not to install the concrete barrier.

At the time he conducted the National Enforcement Investigations Center inspection, Vanlerberghe thought that slop oil tanks S-1 and S-2 were bulk storage tanks; however, he has changed his mind and now believes that they are not bulk storage tanks. In defendant's June 1997 Spill Prevention Control and Countermeasure Plan, defendant states that slop oil tanks S-1 and S-2 are in refinery area B, which is a bulk storage area. Defendant's June 1997 plan does not mention that slop oil tanks S-1 and S-2 drain into American Petroleum Institute Separator #1.

At the time of the May and June 1998 inspections, defendant had not received closure approval from the Department of Natural Resources in the S-1 and S-2 area and had not installed a diked secondary containment area for slop oil tanks S-1 and S-2. After the department gave verbal notification that the site would be closed in September 1999, defendant constructed secondary containment around tanks S-1 and S-2.

2. <u>Claim Eleven</u>

Tanks 21, 22 and 23 began operating in 1961, 1961 and 1964 respectively. When the tanks began operation, they lacked a common diked area with a volume equal to the capacity of the largest tank, plus sufficient freeboard for precipitation, which is an additional 10% of the capacity of the largest tank, according to industry standard. In the May 1995 plan, defendant added tanks 21, 22 and 23 as potential spill sources. According to the May 1995, March 1996 and June 1997 versions of the plan, the largest of tanks 21, 22 and 23 is tank 23, holding 54,248 barrels with a containment area capable of holding 12,840 barrels. In March 1996, defendant amended its Spill Prevention Control and Countermeasure Plan to provide for increasing the capacity of the common diked area for tanks 21, 22 and 23 to a volume equal to the capacity of the largest tank, plus sufficient freeboard for precipitation. Specifically, defendant's amended Spill Prevention Control and Countermeasure Plan stated

> [T]he volume of the diked area at the West Tank Farm is less than the capacity of tanks 21, 22 and 23. Repairs are planned to increase the capacity of the diked areas to a volume equal to the capacity of the largest tank, plus sufficient freeboard for precipitation. Until these repairs are completed, only one tank will remain in service and current operational procedures limit the capacity of this tank to be less than the diked area volume.

Before making this amendment to its plan, defendant had experienced difficulties at other tanks, such as overheating, that had prevented it from limiting tank contents to desired levels and had caused tanks to overflow. According to the March 1996 version of the plan, defendant had experienced spills in the past because of things such as "seal failure," "valve left open" and "tank leaking."

In the plan dated June 1997, defendant discussed secondary containment for Tanks 21, 22 and 23 under the section titled "Bulk Storage." In 1997, defendant installed sufficient secondary containment for the diked areas of tanks 21, 22 and 23. On June 11, 2001, defendant measured the secondary containment area for tanks 21, 22 and 23 and found it had a capacity equal to more than 130% of the largest tank.

3. Claim Twelve

According to the May 1995 and March 1996 versions of defendant's Spill Prevention Control and Countermeasure Plan, Tank 57 had a tank capacity of 89,000 barrels and a diked area capacity of 89,050 barrels. Defendant's March 1996 Spill Prevention Control and Countermeasure Plan had been certified by a professional engineer. The version of its plan that defendant presented to Vanlerberghe during the 1998 inspection stated that Tank 57 had a tank capacity of 89,000 barrels and a diked area capacity of 89,050 barrels.

In February 2000, defendant recalculated the diked area capacity for Tank 57 as equal to more than 110% of the capacity of Tank 57. No changes had been made in the area of Tank 57 since 1995.

4. Claim Thirteen

Defendant's Spill Prevention Control and Countermeasure Plan was certified by a professional engineer on April 4, 1996; however, the plan's November 1996 and June 1997 amendments were not certified by a professional engineer.

During the three years following the April 1996 certification, defendant eliminated potential spill sources and updated the plan's list of potential spill sources. Defendant did not get its Spill Prevention Control and Countermeasure Plan recertified after it had made changes to its list of potential spill sources.

In November 1996, defendant added a new section to its plan entitled "Discharge Detection Systems," describing alarms that would sound automatically in the event of a pipeline leak or rupture, as well as procedures for defendant's personnel to follow when inspecting for equipment leaks, spills, splits and cracks. Also, defendant amended its plan to include visual inspection procedures and checklists. Specifically, defendant added Figures 14.7 and 14.8 (visual inspection procedures for storm water and non-storm water discharges) and Figure 14.9 (an annual facility compliance inspection checklist).

In June 1997, defendant amended its plan to add pumping procedures for an oil sump located in a truck loading area at the refinery. These pumping procedures had not been discussed in earlier versions of defendant's plan. Also, defendant amended its plan to note the refinery's redrawn internal boundaries, which regrouped tanks, drains and other structures at the refinery into six areas instead of nine. Because the plan had described oil storage and operation, sewer and surface drainage and secondary containment at the refinery on an area by area basis, redrawing the internal boundaries at the refinery meant that entire sections of defendant's previous plan were no longer accurate and had to be amended. In June 1997, defendant amended its plan to state that area B of the refinery had a total of 66 tanks; previously its plan had stated that area B had 32 tanks.

## III. RESOURCE CONSERVATION AND RECOVERY ACT

Defendant generates hazardous waste as a byproduct of its manufacturing processes at various locations throughout the refinery. From May 26 to June 4, 1998 and from June 15 to June 19, 1998, inspectors from plaintiff's National Enforcement Investigations Center conducted an environmental inspection of defendant's refinery. Linda TeKrony toured the facility and reviewed records and documents.

At its wastewater treatment plant, defendant generates hazardous waste in the form of sludge, which is processed to remove recoverable oil, leaving thickener sludge containing hazardous solids. Defendant's wastewater treatment plant collects these solids and pipes them to a thickener tank. Sludge that accumulates in the tank is pumped out into large containers and from those containers into 55-gallon drums that are disposed of off-site. On May 28, 1998, TeKrony observed four 55-gallon drums in defendant's wash pad area that were being used to accumulate hazardous wastes, including contaminated gravel, oily pads and rags and wash pad sludges. All of the drums were labeled as hazardous waste and all had covers that formed a continuous barrier over each of the barrels so that there were no visible gaps. Each barrel cover contained a channel around its circumference that fit over the rim of the barrel; this ridge and groove design holds the cover in place in the closed position. None of the covers was secured by a barrel cover locking ring.

Defendant has never been cited for not having a locking ring on a barrel when the barrel is in storage status for fewer than 90 days.

OPINION

I. CLEAN AIR ACT

A. Background

Congress enacted the Clean Air Act "to protect and enhance the Nation's air resources," 42 U.S.C. § 7401(b)(1). In 1970, it charged plaintiff with establishing national ambient air quality standards that would specify the maximum permissible concentrations of certain air pollutants necessary to protect the public health. 42 U.S.C. § 7409. Once these standards had been set, each state could submit a plan providing for implementation of the standards within its borders. 42 U.S.C. § 7410. The law required that the plans be designed to prevent the significant deterioration of air quality in areas designated as "attainment" or "unclassifiable." The states have primary responsibility for enforcing state implementation plans but the plans are enforceable by the federal government as well. 42 U.S.C. § 7413.

Although Congress wanted to speed the clean up of the nation's air, it realized that many existing pollution sources would have difficulty complying with strict new requirements. It provided "grandfather" provisions for those facilities but anticipated that they would incorporate the newly required controls as they underwent modifications or replacement. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990). Not all modifications came under the statute's scope; the law covered only modifications that resulted in net emissions increases. See, e.g., 42 U.S.C. 7411(a)(4) ("'modification' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted").

B. The Need for Prevention of Significant Deterioration Permits for Modifications to Sulfur Recovery Unit

In 1987, when defendant began modifying its sulfur recovery unit, beginning with the installation of the tail gas analyzer, federal law incorporated into Wisconsin's implementation plan prohibited the construction or modification of a "major emitting facility" without a Prevention of Significant Deterioration permit. 42 U.S.C. § 7479. In other words, if defendant planned to make any modifications that consisted of physical changes or changes in operation to a "major emitting source" (a stationary source that emits or has the potential to emit 100 tons a year or more of any air pollutant), such as a sulfur recovery plant, id., it would be required to obtain a permit if the modifications would result in a "significant net emissions increase" of sulfur dioxide. 40 C.F.R. § 52.21(b)(2)(i). A "significant" net emissions increase of sulfur dioxide means an increase in emissions of more than 40 tons a year. 40 C.F.R. § (b)(23)(i).

An increase in emissions is calculated by determining the excess of the source's "potential to emit" over the source's actual emissions before the modifications began. The potential to emit is determined at the time the modification is proposed and is defined as the maximum capacity of a stationary source to emit a pollutant under the source's physical and operational design. See 40 C.F.R. § 52.21(b)(21)(iv). The potential to emit calculation takes into account any legal limits on emissions imposed by state or federal law, as of the time the application is under consideration. That is, if the federal government has set a limit of 100 pounds an hour of emissions of sulfur dioxide, for example, this limit would be considered part of the operating restrictions in determining potential to emit, even if the plant is physically capable of emitting 1000 pounds an hour.

In order to predict the potential increase in emissions, the operator and the permitting authority must know what the plant was emitting during the two years immediately preceding the start of the modifications so as to be able to draw a comparison. The parties have a sharp dispute about the manner in which the pre-construction emissions should be computed, what information is necessary to perform the computation and whether defendant withheld relevant information from the regulators that would have shown that the potential emissions after the changes in 1991-93 would exceed the actual emissions before the construction period by more than 40 tons a year.

Two separate and distinct concepts play a part in determining the need for a Prevention of Significant Deterioration permit. One is "emissions," the amount of sulfur dioxide that actually comes out of the sulfur plant's smoke stack; the other is "recovery rate." Recovery rate refers to the amount of elemental sulfur that is recovered from the waste gases sent to the sulfur recovery unit. The more sulfur is recovered, the higher the recovery rate and the lower the rate of sulfur dioxide emitting into the atmosphere. Emissions can increase if the recovery rate remains the same and the quantity of waste gases coming into the sulfur recovery unit increases; if the quantity of gases remains the same but the recovery rate drops; and, of course, if the waste gas quantity increases and the recovery rate declines.

When predicting whether certain modifications will result in a post-construction increase, it is advantageous for a regulated operator to be able to show that actual (pre-construction) emissions have been high because that will make it less likely that post-construction emissions will show an increase. If an operator suspects that the processing capacity of its unit will increase, thereby producing more emissions, it is to the operator's advantage to show that the rate of recovery of elemental sulfur during the pre-construction baseline period was low and that the rate will improve after construction. For example, if before construction, the operator was able to recover only 80% of the sulfur from the gases and if the operator anticipates a post-construction recovery rate of 95%, the plant can handle 15% more waste gases without an increase in emissions of sulfur dioxide.

To compute the increase, it is necessary to know what the facility has actually been emitting and compare it to the predicted emissions rate once the modifications have been made. 40 C.F.R. § 52.21(b)(21) sets out the procedure for calculating actual emissions. Actual emissions are equal to the average rate in tons per year at which the unit actually emitted the pollutant during a two-year period that preceded the start date and that is representative of normal source operation. Actual emissions are to be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored or combusted during the selected time period. Id.

Sulfur recovery efficiency can be determined in one of three ways: 1) sulfur composition of inlet streams and sulfur emissions; 2) composition of inlet streams plus sulfur production; and 3) sulfur production plus sulfur emissions.

1. 1987-88 Modifications to Sulfur Recovery Unit

Defendant's sulfur recovery unit is a "major emitting facility" because it has the potential to emit 100 tons or more of sulfur dioxide, an air pollutant. The changes made to the sulfur recovery unit in 1987 and 1988 were both physical changes and changes in the method of operation of the unit. The physical changes were the addition of the larger combustion chamber, the tail gas analyzer, a hydrocarbon coalescer, an acid knock-out drum and a distributed control system. The operational changes came about because of the larger combustion chamber, which allowed a longer "cure time" and concomitantly greater conversion of hydrogen sulfide, and the tail gas analyzer, which provided a far more accurate method of insuring that the air and gas mix was optimum at all times. These modifications were "major" if they resulted in an increase of more than 40 tons a year of sulfur dioxide emissions.

Plaintiff's expert, Steven Dunn, calculated defendant's actual emissions rate for the two-year period immediately preceding the installation of the tail gas analyzer in June 1987. (Defendant objects to Dunn's use of an earlier baseline period than he had used for the calculation he made before entry of the order on summary judgment but defendant has shown no prejudice as a result of the change. In fact, it is to defendant's advantage to use the earlier time period because it shows a higher average monthly sulfur production rate. As noted, a higher average benefits defendant: the higher the pre-project emissions rate, the lower the chance that the post-project rate will show an increase.) Dunn performed the calculations in 2001 as if he were doing them in 1987 with the information he had secured in the interim. He began with the average monthly sulfur production rate reported to the Bureau of Mines, which he computed as 142.5. (Defendant objects to the use of the Bureau of Mines reports because information from 7 of the 24 months is missing. Seventeen months gives Dunn enough information to draw a rough average of sulfur production rate. Defendant has not shown that the average he chose misrepresents defendant's actual production rate for that report.)

Although defendant had reported to the Department of Natural Resources that it had a 75-80% recovery rate from its stack tests and the air emissions inventory showed an average recovery rate of 76%, Dunn used an 80% recovery rate. Given the information contained in the Sulfur Operations reports showing that defendant's sulfur recovery unit was operating at 85 to 90% efficiency as of 1986-87, 80% represents a conservative recovery rate. Using an 80% rate of recovery and an average sulfur production of 142.5 long tons a month, Dunn arrived at an actual emission rate of 957.6 tons of sulfur dioxide a year. Had he used the 76% percent recovery rate, he would have had an actual annual emissions rate of 1,210. He calculated the potential to emit as limited to 393 pounds an hour because of the state emissions limitation that was implemented in 1988 and arrived at a total rate of emissions of 1721 tons a year, or an increase of 763.7 tons. Had Dunn used the 1,210 figure for actual emissions derived from a 76% recovery rate, the increase would have been 511 tons a year, still considerably in excess of 40 tons a year. Dunn found no identifiable creditable and contemporaneous emissions reductions to take into consideration.

Defendant believes that Dunn's calculations are irrelevant because the sulfur recovery unit is a pollution control device exempt from Prevention of Significant Deterioration Prevention permit requirements. In the May 18, 2001 opinion, I discussed the parties' dispute about the proper characterization of the sulfur recovery unit and concluded that the determining factor was whether the modifications made to the unit increased pollution. Opin. and Order of May 18, 2001, at 73-77. I stated that if the particular modification did not increase emissions *from the refinery*, then Prevention of Significant Deterioration permitting requirements would not be triggered. Id. at 76. Technically, this statement is accurate if it is understood to refer to the emissions after all refinery-wide creditable emission reductions have been subtracted from any increase in emissions from the particular source, in this case, the sulfur recovery unit. In this instance, however, there were no creditable emission reductions that could be used to offset the increase in emissions from the sulfur recovery unit. Therefore, the only question is whether the changes resulted in an increase of emissions *from the unit* of more than 40 long tons per year.

Plaintiff's expert, Gary McCutchen, testified that it was plaintiff's historical policy to exempt pollution control devices from the Prevention of Significant Deterioration regulations and from New Source Performance Standards, but his testimony was effectively undercut by the July 7, 1986 memorandum from the Director of the Office of Air Quality Planning and Standards. According to the memorandum, there was no automatic exemption from the Prevention of Significant Deterioration permitting requirement for devices with the primary function of reducing air pollution. McCutchen had relied on an earlier, withdrawn memorandum in forming his opinion that the historical policy was to exempt pollution control devices from Prevention of Significant Deterioration requirements.

Defendant objected at trial to the use of 393 pounds an hour as a restriction on production, arguing that when Dunn was computing potential post-construction emissions, he should have used the limit of 281 pounds that the federal government had enacted before 1987. However, in responses to requests for admission filed on February 12, 2001, defendant had agreed that no applicable federal limitation was in effect in 1988 and that the state was enforcing a 393 pound an hour restriction. Defendant's admission bars it from arguing now that Dunn should have used the 281 pound an hour restriction in calculating potential emissions.

Defendant objects to the calculations on another ground, contending that Dunn erred in concluding that there were no creditable emission reductions to offset the increase in emissions after the 1987-88 improvements had been made. 40 C.F.R. § 52.21(b)(3) provides a guideline for "netting out" emissions. A "net emissions increase" means the amount by which the sum of the following exceeds zero:

> (a) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source (hereinafter "First Step");
>
> (b) Any other increases or decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable (hereinafter "Second Step").

For the 1988 major modifications, the sulfur recovery unit is the only emissions unit that was modified. Defendant argues that in computing the potential emissions of this unit, Dunn should have considered the reduction in emissions that resulted from the greater reliability of the sulfur recovery unit and the corresponding reduction in emissions from other parts of the refinery. The flaw in this argument is that any such reductions are not to be considered in the First Step, which is concerned simply with the increase in actual emissions from a *particular* physical change or change in the method of operation. In this step, the inquiry is directed to determining whether there is an increase in emissions at the stationary source that was modified. Dunn's calculations show that there was such an increase. Defendant has not shown that there are any reductions that could be considered in the Second Step. This may be because the pre-improvement emissions from the downstream fuel combustion devices that had to pick up the slack when the sulfur refinery unit was down had a 111 ton per year limit on sulfur dioxide emissions that defendant violated regularly. Eliminating illegal emissions does not produce a creditable emission reduction that can be used in netting.

Despite the fact that the 1987-88 modifications defendant made to the sulfur recovery unit required a Prevention of Significant Deterioration permit before work began, defendant did not apply for a permit or seek exemption from the permitting requirements. This was a violation of the state implementation plan and the Clean Air Act but, as I explained in the May 18, 2001 opinion and order, dkt. #221 at 42-49, it is a one-time violation and not a continuing one. Because plaintiff is not alleging that defendant withheld documents that would have enabled plaintiff to discover the violation, the recovery of monetary penalties is barred by the five-year statute of limitations. Whether plaintiff is entitled to injunctive relief is a matter to be taken up in the next stage of the trial.

2. <u>1991-93 modifications to sulfur recovery unit</u>

a. Aggregation of 1991-93 projects

At the threshold, the parties disagree about the way the various projects should be considered. Plaintiff's position is that all of the work done in 1991-93 should be treated as one project for the purpose of determining whether the project resulted in an increase of emissions; defendant disagrees, arguing that when it began the work it did in 1991-92, it did so with no thought of preparing for the No. 2 distillate unifier project. I conclude that the work should be treated as one project. As early as April 1990, defendant had hired Becker, Losier to help it plan the changes it would have to make to produce low sulfur diesel fuel. E&L's study was directed to proposals that would increase the throughput capacity of the sulfur recovery unit, which was necessary to absorb the additional feed that would be produced by the distillate unifier when it was upgraded. Even earlier, in the late summer of 1989, defendant had solicited help from Western Research in undertaking a sulfur plant capability study for "possible future addition of distillate hydrotreating to the refinery." The changes defendant made in 1991 were designed to increase the throughput capacity: in addition to separating the amine and sulfur recovery systems, defendant added two new blowers, larger seal legs and a new and larger sulfur pit; replaced the heat exchange surface of the waste heat boiler with a larger one; and enlarged the condenser surface area.

Defendant started discussions with the Department of Natural Resources about the changes to the distillate unifier within six months of the completion of its 1991 project. In light of the evidence that the two projects were planned and implemented almost simultaneously and modified the same process unit, I will treat them as one.

b. 1991-93 modifications

The changes defendant made to the sulfur recovery unit in the period 1991-1993 constituted major modifications to a major stationary source and would have required a Prevention of Significant Deterioration permit if they had the potential for a net emissions increase. 42 U.S.C. §§ 7479(1), 7411(a)(3) and (4); 40 C.F.R. §§ 52.21(b)(2)(i) and (b)(2)(ii). Steven Dunn determined that the baseline emission rate for the period August 1, 1989 to August 1, 1990 was 350.9 tons a year and that the potential to emit was 1,230.8 tons a year or 281 pounds an hour. Dunn used the 281 limitation because it was the only federally enforceable limitation. He was not able to identify any contemporaneous and otherwise creditable decreases in actual sulfur dioxide emissions. The resulting increase was 879.9, which is a legally significant increase.

Defendant objects to Dunn's calculation. It contends that Dunn erred by ignoring the 177.4 pounds an hour and 777 long tons a year limit created by defendant's synthetic minor permit and not using them as the maximum potential emissions in doing his calculations. The only limits that Dunn was required to use were those that were in existence at the time defendant would have been applying for the permit it needed to make its 1991-1993 improvements. As of 1991, defendant did not have any physical or operational limits on its emissions other than those set forth in Wis. Admin. Code § NR 417.07. The limits in the yet unissued synthetic minor permit were only a far off possibility. Therefore, Dunn acted correctly in ignoring them.

The re-routing of the sour water gas stripper from the incinerator to the sulfur recovery unit led to a reduction in emissions but defendant has not shown that this reduction would be creditable or that it would have brought the emissions below the permitted rate. For a reduction to be creditable, the reduction must result from implementation of a state or federally enforceable order. Defendant has not shown that before it began actual construction of the sulfur recovery unit modifications either plaintiff or the department had issued an order requiring defendant to close down its sour water stripper incinerator. Therefore, it has not shown that any resulting emission decreases are creditable under 40 C.F.R. § 52.21(b)(3)(i)(*b),* (b)(3)(ii)-(vi).

I conclude that when defendant applied for a synthetic minor source permit, it was not eligible for one. Instead, it should have been subject to Prevention of Significant Deterioration permitting requirements as well as the requirements of New Source

Performance Standards.

C. Failure to Submit Information

Pursuant to 40 C.F.R. § 52.21, which has been incorporated into Wisconsin's state implementation plan, owners or operators of a proposed source or modification must submit "all information necessary to perform any analysis or make any determination required under this section." Such information is to include "emission estimates, and any other information necessary to determine that best available control technology would be applied." Id. Congress has authorized plaintiff to respond to violations of the state implementation plan by issuing an order requiring compliance, assessing an administrative penalty order or initiating a civil action. 42 U.S.C. § 7413.

When defendant applied for a minor source permit in July 1992, it did not provide the Wisconsin Department of Natural Resources the 1989 Western Resources report, two reports from Becker, Losier & Associates and four reports from Sulfur Operations Support. The Western Resources report contained data that were relevant to determining defendant's baseline emissions for the two years preceding defendant's permit application, including the results of a performance test. This is a particularly egregious failure given defendant's emphasis on the greater reliability of performance tests over stack tests in determining recovery efficiencies. It is unlikely that the department would have allowed defendant to use the 82% recovery efficiency defendant said it had obtained from the September 13, 1989 test had it known that six days later, on September 19, 1989, Western Research had estimated a recovery efficiency of 93.3% to 95.1% from its test of the same stack. It is equally unlikely that the department would have accepted an average recovery rate of 86% (the combined recovery rates of the September 13, 1989 and the October 31, 1989 tests) had it known that Western Research's test results on October 24 and 26, 1989, showed a 96.04% recovery rate or known of the results of the firm's material balance. Even if, as defendant argues, these tests were conducted under optimal operating conditions, they showed what the unit was capable of and cast a dim light on the accuracy of the September 13 test. More to the point, if defendant thought the reports were unreliable, it could have explained to the Department of Natural Resources any alleged deficiencies in the reports. As I have found, the Western Research information would have affected the department's decision to approve a synthetic minor permit for defendant. Without this information, neither the department nor plaintiff had any reason to believe that the synthetic minor permit should not have issued to defendant. Plaintiff's visit to the refinery during the comment period would not have alerted it to the nature and extent of the modifications defendant had made to the sulfur recovery unit and would be making to the distillate unifier.

Although Department of Natural Resources employees were present at defendant's refinery on a number of occasions, they were not made aware of the contents of the letters and reports defendant was sending and receiving and they would not have known the exact nature of the changes defendant planned to make in the sulfur recovery unit or even that the changes had been made until well after the fact. Defendant did tell Dan Rosenthal about the re-routing of the sour water stripper gas but not until about two years after defendant had submitted information on the 1991-93 modifications to the department with no mention of the re-routing plan.

Defendant has argued at length about plaintiff's alleged inability to show that in fact defendant did not produce the reports plaintiff now says were relevant to the decisions the Department of Natural Resources had to make in 1987, 1990 and 1992. Defendant is correct in alleging that many of plaintiff's files are incomplete or missing. However, there is ample evidence that defendant did not submit the reports. First, there is the undeniable significance of the reports. It is difficult to believe that had reports of this importance been submitted to the department, the department would have taken the actions it did. For example, it defies logic to think that the permitting examiner would have ignored Dan Rosenthal's pleas to use a higher recovery rate for the 1990-92 baseline had the examiner seen the Sulfur Operations or Western Research reports on the efficiency rates these consultants were observing and the problems with the September 13, 1989 stack test. Second, at trial, plaintiff asked defendant's employees who had been working with the department on the various projects whether they had sent the reports at issue to the department during the course of their negotiations on the projects. All of them denied having done so, although they were employees who would have been responsible for doing so. Third, Paul Yeung would not have written the reassuring letter to the Superior residents who had commented on the department's proposal to issue a synthetic minor permit to defendant had he known that defendant's proposed modifications would be increasing the emissions level from the sulfur recovery unit.

If there is any doubt about this point, it is laid to rest by Lee Vail's withholding of the Western Research report in 1999, when plaintiff and the Department of Natural Resources were investigating defendant and the department was discussing proper recovery efficiencies with Vail. Although Vail had had the report in his possession since before June 1999 and was aware that the department questioned the use of the 86% rate, he continued to argue that there was no evidence to support a conclusion that defendant's rate could have exceeded 90% in 1989. Indeed, his correspondence with the department seems intended to accuse it of reneging on its previous determination that 86% was the accurate recovery rate for determining defendant's pre-construction emissions.

There remains the question whether defendant could have been expected to know that the withheld reports were relevant. It argues that it would have been improper to submit information to the department that it believed was inaccurate or misleading and that it had never been made aware of any obligation to submit consultants' reports.

Defendant's argument would have considerable force if defendant had advised the department of the essence of the information contained in the reports. Defendant would not have needed to submit the reports had it told the department, for example, that it wanted to use the results of a September 13, 1989 stack test but that the test had been performed on a day when the sulfur recovery unit was not operating properly because diethylamine had been leaking into the Claus section. Whether defendant submitted the reports or not, it had a duty 1) to advise the department that although it believed the accurate efficiency rating of the sulfur recovery unit in 1989 was 86%, it had test results from its consultants that showed that this rate might not be accurate; 2) to tell the department that it was planning to make much more extensive changes in the sulfur recovery unit in 1991-1993 than simply separate the amine and sulfur recovery systems; and 3) to insure that the department knew the exact nature of those changes and their effect on the capacity of the unit. However, defendant kept this and other critical information from the Department of Natural Resources and from plaintiff. As a result, the department was unable to make an accurate evaluation of defendant's application for a synthetic minor permit and its eligibility for exemption from New Source Performance Standards.

Finally, defendant contends that the loss and destruction of Wisconsin Department of Natural Resources documents implies that the contents of those documents would be favorable to defendant. It cites Brown & Williamson Tobacco Corp. v. Jacobson, 827 F.2d

1119, 1134 (7th Cir. 1987); S.C. Johnson & Son, Inc. v. Louisville & Nashville Railroad Co. 695 F.2d 253, 259 (7th Cir. 1982), for the proposition that a party's destruction of documents in the face of pending litigation is evidence that the party believed the documents contained evidence harmful to it. Defendant omits mention of the two-prong test that the court of appeals applies: the party asking that the inference be drawn must show that (1) the missing evidence is likely to have been favorable to the party asking for the adverse inference and (2) the party responsible for the missing evidence acted in bad faith. S.C. Johnson, 695 F.2d at 258-59. Nothing in the record supports a finding that the missing evidence is likely to be favorable to defendant or that employees of the Wisconsin Department of Natural Resources acted in bad faith in deleting e-mail messages or misplacing files.

I conclude that defendant withheld information knowingly and intentionally and that if it had submitted the withheld materials, they would have been material to the department's decision making process. Because the department issued a synthetic minor air permit to defendant only because defendant had withheld material information, defendant cannot rely on the permit shield defense, that is, the defense that compliance with an air permit constitutes compliance with all applicable air pollution laws. Furthermore, the withholding of the information means that defendant cannot rely on the argument that Wis. Stat. § 285.81(4) bars plaintiff from pursuing its Clean Air Act claims against defendant because plaintiff did not challenge the department's decision to issue defendant a synthetic minor source permit in 1992, even though it had notice from the department of the permit's issuance.

In the May 18, 2001 opinion and order, dkt. #221, I held that the 30-day deadline in § 285.81(1) would bar plaintiff from challenging permits and determinations issued years ago by the Department of Natural Resources. The only exception available to plaintiff was to show that because defendant had withheld relevant information plaintiff had no reason to suspect that the permit did not conform to the requirements of the state implementation plan or the Clean Air Act. Plaintiff has made the required showing to avoid the bar in § 285.81(1).

I reach a similar conclusion with respect to defendant's affirmative defense that Wis. Stat. § 285.81(4) bars plaintiff from challenging defendant's 1992 air permit. Like subsection (1) of § 285.81, subsection (4) bars challenges to regulatory determinations only if the underlying determinations were based on defendant's submission of full, candid and accurate information. Now that plaintiff has shown that defendant withheld material information, defendant cannot hide behind the protections of § 285.81(4).

D. Applicability of New Source Performance Standards

The New Source Performance Standards program, 42 U.S.C. § 7411, requires plaintiff to issue federal performance standards for categories of new stationary sources that cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. A new source is "any stationary source, the construction or modification of which is commenced after the publication of" an applicable performance standard. 42 U.S.C. § 7411(a)(2). Plaintiff promulgated New Source Prevention Standards for petroleum refineries. These standards are codified at 40 C.F.R. Part 60, Subpart J, §§ 60.100 to 60.109. Subpart J applies to certain "affected facilities" within a facility, including Claus sulfur recovery units with a capacity greater than 20 long tons a day, on which construction or modification is begun after October 4, 1976. Those units subject to Subpart J must meet a specified emission limit and must comply with certain monitoring and record keeping requirements.

As a corporation owning or operating a petroleum refinery, defendant is a "person" that owns or operates a "stationary source." 42 U.S.C. § 7602(e). Defendant's sulfur recovery unit is subject to Subpart J if defendant modified the unit after October 4, 1976, if the unit's sulfur input capacity is greater than 20 long tons a day of sulfur, making it an "affected facility," and if the changes to the unit resulted in an increase in the rate of sulfur dioxide emissions. The term "modification" under the New Source Performance Standards means "any physical change in or change in the method of operation of, an existing facility which increases the amount of any air pollutant . . . emitted into the atmosphere by that facility . . . ." 40 C.F.R. § 60.2.

To understand the parties' dispute over the applicability of the New Source Performance Standards and how it differs from their dispute over the need for a Prevention of Significant Deterioration permit at issue in claim one, it helps to keep in mind that the provisions governing the New Source Performance Standards apply to any modification to a plant that results in *any* increase in emissions, but that the standards do not apply to any Claus sulfur recovery plant of 20 long tons per day or less. The parties disagree whether defendant's sulfur recovery unit is exempt from the standards. Their disagreement centers on two questions: whether the 20 long tons a day limit refers to the amount of sulfur produced or to the amount of "feed" coming into the plant (with feed consisting of the streams of sour water stripper off-gas and amine acid gas), and whether if defendant is correct in its position that the limit applies to input (throughput), the modified plant was designed to process a sulfur feed of more than 20 long tons a day for even a short period.

There is little to defendant's argument about the measurement of capacity. It is clear from letters and statements made by defendant's employees that when they were advising the Department of Natural Resources that the capacity of defendant's sulfur recovery unit was less than 20 long tons a day, they understood the measurement to be feed, that is processing capacity or input or throughput. David Petty used the term throughput in his letter of May 21, 1990, when he told the Department of Natural Resources that the changes proposed to be made in 1991-92 would not increase the throughput capacity of the sulfur recovery unit, which had a design capacity of 14 long tons a day. Mark Miller testified at trial that he believed that the sulfur recovery unit had a maximum sulfur input rate of less than 15 long tons a day.

It has been clear since October 25, 1979, that the standard for assessing the capacity of a sulfur recovery unit has been processing capacity, that is, the unit's ability to process a certain amount of input. See 44 Fed. Reg. 61,542 (Oct. 25, 1979). Although plaintiff introduced some confusion into the question through a June 2, 1992 memorandum, that memorandum was quickly rescinded by another one issued on October 22, 1992, by John Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality and Standards, in which Rasnic confirmed that the 20 long ton per day applicability exemption does not refer to the amount of sulfur the plant is designed to produce. Moreover, June 2, 1992 was after defendant had formulated most of its plans for increasing the capacity of the sulfur recovery unit. Defendant is not credible when it takes the position that it would not have known in 1990 or 1991 that the 20 long ton a day limitation referred to input.

I have found as fact that the design capacity of defendant's sulfur recovery unit exceeded 20 long tons a day. It is true that defendant did not run it at this level on a frequent basis but the determining point is that defendant *could* operate the unit at this level if it wanted to or if the acid feed loads required it. Moreover, the evidence is that on occasion, defendant *did* operate the unit at more than 20 long tons a day. Therefore, I conclude that when defendant applied for a synthetic minor permit in 1992, it was not eligible for exemption from the New Source Performance Standards applicable to sulfur recovery units with a design capacity of less than 20 long tons a day.

## II. CLEAN WATER ACT

### A. Clean Water Act: Claims Ten, Eleven, Twelve and Thirteen

The Clean Water Act is intended to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." 33 U.S.C. § 1251(a). The act prohibits the discharge of oil or hazardous substances into or upon the navigable waters of the United States or adjoining shorelines in such quantities as have been determined may be harmful to the public health or welfare or environment of the United States. 33 U.S.C. § 1321(b)(3). Pursuant to the act, plaintiff has promulgated the spill prevention control and countermeasures regulations, 40 C.F.R. Part 112, that "establish[] procedures, methods and equipment and other requirements for equipment to prevent the discharge of oil from non-transportation related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines." 40 C.F.R. § 112.1(a).

The spill prevention control and countermeasures regulations apply to owners and operators such as defendant that are engaged in refining oil and oil products and that might be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States or adjoining shorelines. 40 C.F.R. § 112.1(b). Facility owners are under an obligation to maintain Spill Prevention Control and Countermeasure Plans and amend them whenever there is a change in facility design, construction, operation or maintenance that materially affects the facility's potential for the discharge of oil into or upon the navigable waters of the United States or adjoining shorelines. 40 C.F.R. § 112.5. Operators are to implement the amendments as soon as possible, "but not later than six months after such change occurs." Id. Moreover, any amendment must be certified by a professional engineer before it becomes effective. § 112.5(c). Operators required to prepare a spill prevention plan must complete a review and evaluation of the plan at least once every three years from the date the facility becomes subject to the regulations. 40 C.F.R. § 112.5(b). The parties agree that defendant was required to prepare a written Spill Prevention Control and Countermeasure Plan.

1. Claim Ten

Claim ten concerns defendant's alleged failure to take timely measures to implement an amendment to its Spill Prevention Control and Countermeasure Plan by failing to provide a sufficient secondary containment area for its slop oil tanks S-1 and S-2. (Plaintiff is seeking damages only and not injunctive relief for claim ten because defendant installed a sufficient secondary diked containment area in 1999.) Specifically, plaintiff contends that defendant failed to install adequate secondary containment for tanks S-1 and S-2 until 1999, three and a half years after defendant had said explicitly in its May 1995 plan that slop oil tanks S-1 and S-2 were potential spill sources and did not have secondary containment.

Federal regulations provide for more time to prepare and implement spill prevention control and countermeasure plans for new facilities, 40 C.F.R. § 112.3(b) (plan must be submitted within six months and fully implemented within a year after new facility begins operation), than for modifications of pre-existing facilities, 40 C.F.R. § 112.5(a) (plan must be amended whenever existing facilities modified and such amendments must be fully implemented within six months of modification). See Pepperell Associates v. United States, 246 F.3d 15, 27 (1st Cir. 2001). The addition of two slop oil tanks qualifies as a "change in facility design, construction, operation or maintenance which materially affects the facility's potential for the discharge of oil." 40 C.F.R. § 112.5(a). The parties agree that slop oil tanks S-1 and S-2 did not have adequate secondary containment at the time of the 1998 inspection. Their only dispute is whether defendant was required to have installed such containment within six months of the addition of slop oil tanks to its May 1995 plan.

The threshold question is whether slop oil tanks S-1 and S-2 are bulk storage tanks subject to 40 C.F.R. § 112.7(e)(2)(ii), which provides that "All bulk storage tank installations should be constructed so that a secondary means of containment is provided for the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation." If slop oil tanks S-1 and S-2 are not bulk storage tanks, they are subject to the requirements of § 112.7(c), instead of the more stringent requirements of § 112.7(e)(2)(ii). Section 112.7(c) requires an operator to provide appropriate containment or diversionary structures or equipment for structures that are not bulk tanks so as to prevent discharged oil from reaching a navigable water course. Defendant contends that § 112.7(e)(2)(ii) does not apply to it for three reasons: (1) the tanks are production facilities, not bulk storage tanks; (2) defendant had not received notification from the Department of Natural Resources that the investigation of the site surrounding tanks S-1 and S-2 had been completed; and (3) it did not need diked containment areas for tanks S-1 and S-2 because they drained into American Petroleum Institute Separator Number 1, a device that separates oil and water.

Plaintiff failed to prove that slop oil tanks S-1 and S-2 are bulk storage tanks rather than production facilities. Although defendant argues that tanks S-1 and S-2 are not bulk storage tanks because they are used to separate oil and water, it classified tanks S-1 and S-2 as "bulk storage tanks" in its June 1997 plan. However, the only witness plaintiff called to testify about the nature of slop oil tanks S-1 and S-2 said that they were not bulk storage tanks. Fortunately, it is not necessary to characterize the nature of the tanks in order to resolve this issue. Whether or not slop oil tanks S-1 and S-2 qualify as bulk storage tanks, defendant violated § 112.5(a) by failing to implement an amendment to its plan within the time required by the Clean Water Act regulations.

Defendant failed to show that it could not install adequate secondary containment or a diversionary structure for tanks S-1 and S-2 until it received site closure notification from the Wisconsin Department of Natural Resources. If, as defendant tries to argue, it had been faced with a true conflict between its obligations to the state and federal governments, it could have requested an extension of time from plaintiff in which to comply with 40 C.F.R. § 112.7, or informed the Department of Natural Resources that it was facing a federal deadline; defendant failed to do either. Section 112.7 does not provide an exemption that would allow an operator of bulk storage tanks to put off the provision of secondary containment areas until it obtains a decision on site closure from the state regulatory authority. Even it did, the exemption would not apply to defendant because its time for installing adequate secondary containment or a diversionary structure for slop oil tanks S-1 and S-2 expired as of November 1995 (six months after the addition of tanks S-1 and S-2 to its plan), more than a year before the Department of Natural Resources notified it of the need to take remedial action at the site of slop oil tanks S-1 and S-2.

According to plaintiff, without the appropriate containment for tanks S-1 and S-2, a spill would have reached the storm sewer, which has a direct connection to navigable waters. At trial, defendant argued for the first time that it did not need to install adequate secondary containment because tanks S-1 and S-2 drain into American Petroleum Institute Separator Number 1. Even if this is true, it would be insufficient to meet the requirements of § 112.5(a) when defendant never specified the separator as an alternative to secondary containment in its Spill Prevention Control and Countermeasure Plans. To the contrary, defendant described the secondary containment for slop oil tanks S-1 and S-2 as inadequate in the plans it prepared. Regardless whether slop oil tanks S-1 and S-2 were subject to the requirements of § 112.7(e)(2)(ii) or § 112.7(c), defendant violated 40 C.F.R. § 112.5(a) and 33 U.S.C. § 1321 by failing to implement its addition of slop oil tanks S-1 and S-2 as potential spill sources to its May 1995 plan because it did not specify the nature of the containment or diversionary structure and because it did not install adequate secondary containment within six months of the addition of the tanks to the refinery site.

2. Claim Eleven

In claim eleven, plaintiff alleges that defendant failed to implement an amendment to its Spill Prevention Control and Countermeasure Plan by failing to provide sufficient capacity for the common diked area for tanks 21, 22 and 23 within six months of the addition of these tanks to the refinery, which occurred sometime before defendant's amendment of its plan in May 1995 to include these tanks. The addition of tanks 21, 22 and 23 qualifies as a "change in facility design, construction, operation or maintenance which materially affects the facility's potential for the discharge of oil." 40 C.F.R. § 112.5(a). As a result, defendant was required to have the amendment "fully implemented as soon as possible, but not later than six months after such change occurs." Id. Defendant does not contest that tanks 21, 22 and 23 are bulk storage tanks subject to the restrictions of § 112.7(e)(2)(ii); however, it argues that it did install sufficient secondary containment for the diked areas of tanks 21, 22 and 23 in 1997 and that before it did so, it did not use tanks 21 and 22 and did not fill tank 23 to its capacity in order to prevent spills.

Even if defendant did not fill all three tanks to capacity, there remained a potential for operator error or tank failure, resulting in the tanks' filling to capacity and spilling. Such spills had occurred in the past and is the reason that § 112.7(e)(2)(ii) does not authorize operational limits on tank filling as a spill prevention device. Defendant's plans from 1995, 1996 and 1997 show that the containment area for tanks 21, 22 and 23 could hold only 24% of the capacity of the largest tank, far below the requisite 110%. This is conclusive evidence that defendant violated 40 C.F.R. § 112.5(a) and 33 U.S.C. § 1321 by failing to implement its May 1995 plan amendment because it did not specify in the plan that there was adequate secondary containment for tanks 21, 22 and 23 in accordance with § 112.7(e)(2)(ii) and it did not install adequate secondary containment.

3. Claim Twelve

The question in claim twelve is whether defendant violated 40 C.F.R. § 112.7(e)(2)(ii) by failing to provide Tank 57 with sufficient freeboard to allow for precipitation. Section 112.7 sets forth the "Guidelines for the preparation and implementation of a Spill Prevention Control and Countermeasure Plan." Specifically, § 112.7 provides that "[t]he SPCC Plan shall be a carefully thought-out plan, prepared in accordance with good engineering practice. . . . The complete SPCC Plan shall . . . include a discussion of the facility's conformance with the appropriate guidelines." 40 C.F.R. § 112.7(e)(2)(ii) directs operators to include in their plans a discussion of conformance with the requirement that "[a]ll bulk storage tank installations should be constructed so that a secondary means of containment is provided for the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation."

According to the May 1995, March 1996 and June 1997 versions of defendant's plan, the diked area for Tank 57 was capable of holding only 50 barrels more than the tank's capability, far short of the 8900 barrels that would have been required to meet the industry standard. Defendant measured the capacity of the secondary containment area of Tank 57 in February 2000 and found it to be 98,734 barrels. Defendant argues that because it had not added to the containment area since 1995, its belated measurement showed that it had never been in violation of the Clean Water Act. Defendant is wrong. An owner of a facility who is required to maintain an updated Spill Prevention Control and Countermeasure Plan and the engineer who certifies the plan are responsible for insuring that the information in the plan is accurate. It is not plaintiff's responsibility to check all of the information in spill prevention plans; to the contrary, plaintiff is entitled to rely on the information provided in the plan. Accordingly, I conclude that defendant violated 40 C.F.R. § 112.7(e)(2)(ii) and 33 U.S.C. § 1321.

4. <u>Claim Thirteen</u>

Claim thirteen concerns defendant's alleged failure to have a professional engineer certify its November 1996 and June 1997 amendments to its Spill Prevention Control and Countermeasures Plan. Specifically, plaintiff alleges that defendant made the following amendments to its plan in November 1996 and June 1997: eliminated potential spill sources and updated the plan's list of potential spill sources; added a section entitled, "Discharge Detection Systems"; identified visual inspection procedures and checklists; added pumping procedures for an oil sump; and noted that it had redrawn internal boundaries at the refinery.

40 C.F.R. § 112.5(a) requires "owners or operators" to amend their plans "whenever there is change in facility design, construction, operation or maintenance which materially affects the facility's potential for the discharge of oil." Defendant does not dispute its failure to have the relevant amendments certified pursuant to § 112.3(d). Instead, it contends that

the amendments were not the type that required certification by a professional engineer because they were merely housekeeping procedures or procedures that had been in place before. The problem with defendant's argument is that the regulations do not draw such distinctions.

I am persuaded that the November 1996 and June 1997 amendments are operational changes that "materially affect[] the facility's potential for the discharge of oil." As a result, defendant was required to have the amendments "certified by a Professional Engineer in accordance with § 112.3(d)" before the amendments could become effective. 40 C.F.R. § 112.5(c). See also § 112.3(d) ("By means of this certification the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the SPCC Plan has been prepared in accordance with good engineering practices.") Accordingly, I find that defendant violated 40 C.F.R. § 112.5(c) and 33 U.S.C. § 1321.

## III. RESOURCE CONSERVATION AND RECOVERY ACT

The Resource Conservation and Recovery Act, 42 U.S.C. §§ 6921-6939e, establishes a comprehensive statutory scheme for the management of hazardous wastes from the initial generation until the final disposal. Pursuant to 42 U.S.C. § 6926(b), a state may apply for and receive authorization to enforce its own hazardous waste management program if the state requirements are consistent with and equivalent to the federal requirements. If the federal government approves of the state hazardous waste program, the requirements of the state program are effective in place of the federal hazardous waste management program under 40 C.F.R. part 260. The state of Wisconsin has promulgated hazardous waste management regulations, Wis. Admin. Code ch. NR 600-680, for which it has received approval from plaintiff to administer.

In the portion of claim fifteen that went to trial, plaintiff alleges that investigators from the Environmental Protection Agency observed four 55-gallon drums that were covered but not secured by their locking mechanisms (barrel cover locking rings) in violation of Wis. Admin. Code § NR 615.05(4)(a)2.e. Section NR 615.05(4)(a)2.e. provides that "[a] container holding hazardous waste shall always be closed during storage except when it is necessary to add or remove waste." The regulation does not define what it means by "closed" and it makes no reference to locking devices. According to plaintiff, the four drum covers were open because they were not secured by covers with barrel locking rings. Plaintiff's argument centers on the purpose of the Resource Conservation and Recovery Act and the interplay of § 615.05(4)(a)2.e with the regulations as a whole.

Although the four 55-gallon drums were not secured by covers with barrel locking rings, each of the barrels had a cover that had a ridge that fit the rim of the barrel and that formed a continuous barrier over each of the barrels so that there were no visible gaps. The language of Wis. Admin. Code § NR 615.05(4)(a)2.e does not require locking rings on barrels. Plaintiff failed to provide any support for its assertion that the regulations require locking rings. Plaintiff did not warn defendant that it interpreted § NR 615.05(4)(a)2.e to require locking rings on barrels, even when the barrels are being stored for fewer than 90 days. I am not persuaded that plaintiff has shown that barrels are not "closed" within the meaning of the administrative code when they are secured with covers that remain in place because the ridge on the cover fits into the groove in the barrel. The portion of claim fifteen relating to the four 55-gallon drums will be dismissed.

## ORDER

IT IS ORDERED that defendant Murphy Oil USA, Inc. is liable to plaintiff United States of America for defendant's violation of

1) 42 U.S.C. § 7475(a)(1), 40 C.F.R. § 52.21(i) and Wis. Admin. Code § 405.07 by making modifications to its sulfur recovery unit in 1987-88 and 1991-93 without securing a Prevention of Significant Deterioration permit (Count 1);

2) 42 U.S.C. § 7475(a)(1), 40 C.F.R. § 52.21(i) and Wis. Admin. Code §§ NR 405.08(3) and NR 405.07(1) by failing to apply best available control technology to its sulfur recovery unit in connection with the 1987-88 and 1991-93 modifications it made to its sulfur recovery unit;

3) 42 U.S.C. § 7475(a)(1), 40 C.F.R. § 52.21(n) and Wis. Admin. Code § NR 405.12

by failing to turn over relevant information to plaintiff that would have affected plaintiff's decision making in connection with the modifications it made to its No. 2 distillate unifier in 1992-93 (Count 3);

4) 42 U.S.C. § 7413(a)(1), 40 C.F.R. § 60.104(a)(2) by failing to operate its sulfur recovery unit in conformance with the applicable New Source Performance Standards (Count 4);

5) 33 U.S.C. § 1321 and 40 C.F.R. § 112.5(a) by failing to implement an amendment to its Spill Prevention Control and Countermeasure Plan within the time set by the regulation with respect to slop oil tanks S-1 and S-2 (Count 10);

6) 33 U.S.C. § 1321 and 40 C.F.R. § 112.5(a) by failing to implement an amendment to its Spill Prevention Control and Countermeasure Plan within the time set by the regulation with respect to Tanks 21, 22 and 23 (Count 11);

7) 33 U.S.C. § 1321 and 40 C.F.R. § 112.7(e)(2) by failing to provide Tank 57 adequate secondary containment volume with sufficient freeboard to provide for precipitation (Count 12); and

8) 33 U.S.C. § 1321 and 40 C.F.R. § 112.5(c) by failing to have the November 1996 and June 1997 amendments to its Spill Prevention Control and Countermeasure Plan certified by a professional engineer (Count 13).

FURTHER, IT IS ORDERED that plaintiff's claim under the Resource Conservation and Recovery Act based on defendant's alleged failure to keep its four 55-gallon drums closed during storage is DISMISSED.

A scheduling conference will be held by telephone on Wednesday, August 8, 2001, at 8:30 a.m. to set a date for the damages phase of the trial and associated deadlines. The United States Attorney shall be responsible for initiating the conference call.

Entered this 1st day of August, 2001.

BY THE COURT:

BARBARA B. CRABB
District Judge