UTAH STATE IMPLEMENTATION PLAN
CONTROL STRATEGIES

FINE PARTICULATE MATTER (PM10)
SECTION IX, PART A

SECTION IX.A.1 AREA DESIGNATION BACKGROUND

The Wasatch Front Intrastate Air Quality Control Region (AQCR), comprised of Davis, Salt Lake, Utah, and Weber Counties was designated by the Environmental Protection Agency (EPA) as a non-attainment area for total suspended particulate matter (TSP) in accordance with the requirements of Section 107, Clean Air Act as amended August 1977. In 1981, the nonattainment areas were redefined as the actual areas of nonattainment and only those portions of each of the four counties in which monitored and/or modeled data showed that ambient concentrations exceed the National Ambient Air Quality Standard (NAAQS) for TSP were designated as nonattainment areas. In 1983, Davis and Weber Counties were redesignated as attainment areas for TSP.

In 1987, EPA determined that only those particulates with a diameter of ten microns or less (PM_{10}) penetrate into the respiratory tract sufficiently deep to cause a health impact. There are primary and secondary sources of PM_{10}. Primary sources are those which emit PM_{10} directly into the atmosphere from chemical, mechanical, or combustion processes. Secondary PM_{10} particles form from the reactions of SO_2 and NO_x emitted to the atmosphere to form sulfates and nitrates. These secondary sulfates and nitrates are measured at monitoring stations as PM_{10}.

On July 1, 1987, EPA promulgated a new NAAQS for PM_{10} and required the submittal of a State Implementation Plan for those areas not meeting the standards. The 24-Hour NAAQS for PM_{10} is 150 :g/m^3 and it allows up to three exceedances of the standard in any three-year period. Based on historical TSP data, EPA listed Salt Lake and Utah Counties as Group I areas for PM_{10}, which indicated that there was at least a 95% probability that those areas would exceed the new PM_{10} standard. The remainder of the State was listed as Group III, indicating less than a 20% probability of exceeding the PM_{10} standard.

Monitoring data confirms that Salt Lake and Utah Counties exceed the NAAQS for PM_{10}. The State will continue to evaluate the adequacy of the existing ambient air monitoring network described in "Air Quality Surveillance", Section 4 of the SIP. The program will be updated as necessary, to include any revisions of applicable federal regulations and assure attainment of NAAQS for PM_{10}.

The Clean Air Act Amendments of 1990 redesignated the Salt Lake and Utah County Group I areas as non-attainment areas, and required the submittal of a State Implementation Plan which requires the installation of Reasonable Available Control Measures (RACM) on industrial sources impacting the nontattainment areas, and demonstrates attainment of the standard no later than December 31, 1994.

The design value is the ambient pollutant concentration from which this plan must reduce to meet the NAAQS and may be determined by using the actual observed concentrations in the nonattainment area during a specified period of time. The determination of the design value is dependent on the number of days that ambient PM_{10} data were collected during the three-year period, and the data used must be contained in discreet 12-month periods (i.e., 12, 24, or 36-month periods of data collection). This is discussed in more detail in 9.A.4(2) below.

SECTION IX.A.2 PM10 CONCENTRATIONS

Ambient monitoring data has confirmed that violations of the NAAQS occur in Salt Lake and Utah Counties. Table IX.A.1 below shows the numbers of exceedances measured in Utah and Salt Lake Counties since 1985. It also shows the months when the exceedances occurred. As can be seen, most of the exceedances occur during the winter months. During the winter, extremely strong temperature inversions develop which trap PM_{10} particles and all other pollutants in a layer near the ground. The exception to this winter scenario is the occasional wind storm which can cause blowing dust. The exceedances which occurred at the Magna monitoring site are examples of this condition.

DISTRIBUTION OF EXCEEDANCES

STATION	YEAR	JAN	FEB	MAR	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
LINDON	85			0	0	0	0	0	0	0	0	0	7	7
LINDON	86	6	0	0	0	0	0	0	0	0	0	0	0	6
LINDON	87	0	0	0	0	0	0	0	0	0	0	0	0	0
LINDON	88	5	5	0	0	0	0	0	0	0	0	0	6	16
LINDON	89	11	7	0	0	0	0	0	0	0	0	0	2	20
LINDON	90	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH PV	86	1	0	0	0	0	0	0	0	0	0	0	0	1
NORTH PV	87	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH PV	88	1	1	0	0	0	0	0	0	0	0	0	0	2
NORTH PV	89	1	0	0	0	0	0	0	0	0	0	0	1	2
NORTH PV	90	0	0	0	0	0	0	0	0	0	0	0	0	0
WEST OREM	88										0	0	3	3
WEST OREM	89	7	6	0	0	0	0	0	0	0	0	0	2	15
WEST OREM	90	0	0	0	0	0	0	0	0	0	0	0	0	0
SALT LAKE	87							0	0	0	0	0	0	0
SALT LAKE	88	1	0	0	0	0	0	0	0	1	0	0	1	3
SALT LAKE	89	2	1	0	0	0	0	0	0	0	0	0	0	3
SALT LAKE	90	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SL	85										0	0	1	1
NORTH SL	86	1	0	0	0	1	1	0	0	0	0	0	0	3
NORTH SL	87	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SL	88	1	1	0	1	1	0	0	0	0	0	0	3	7
NORTH SL	89	2	1	0	0	0	0	0	0	0	0	0	0	3
NORTH SL	90	0	0	0	0	0	0	0	0	0	0	0	0	0
AMC	89	5	1	0	0	0	0	0	0	0	0	0	1	7
AMC	90	0	0	0	0	0	0	0	0	0	0	0	0	0
MAGNA	85						1	1	1	0	0	0	0	3
MAGNA	86	0	0	0	0	1	0	2	0	0	0	0	0	3
MAGNA	87	0	0	0	1	0	1	0	0	0	0	0	0	2
MAGNA	88	0	0	1	1	0	0	0	0	0	0	0	0	2
MAGNA	89	0	0	0	0	0	0	0	0	0	0	0	0	0
MAGNA	90	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE 9.A.1

Because the violations of the PM_{10} standard in the nonattainment areas are caused by different conditions, and because each of the conditions must be resolved in a different manner, this plan will address the ambient data, design value, and source apportionments for each of the monitoring sites in Utah County nonattainment area, the Magna portion of the Salt Lake nonattainment area, and the remainder of the Salt Lake nonattainment area separately, and then address the control strategies for the entire Wasatch Front. As is demonstrated later in this document, because the exceedances in Salt Lake County are monitored in northern Salt Lake County, and because modeling indicates that sources of PM_{10} and its precursors in Davis County impact the Salt Lake nonattainment area, for purposes of this SIP, controls required in the Salt Lake nonattainment area will be required in Davis County.

SECTION IX.A.3 UTAH COUNTY

The documentation for the development of the emissions inventory, the Chemical Mass Balance model (CMB), MOBILE6 and other mobile emissions, and control strategy effectiveness for the July 3, 2002 revision to the Utah County portion of the PM10 SIP are contained in Supplement II-02 of the Technical Support Document. Detailed calculations for each sector of the emissions inventory for 2002, 2003 (and, for purposes of conformity, 2010 and 2020) are contained in Supplement II-02 of the TSD. These calculations document current planning assumptions about growth, current and projected controls, banked emissions relied upon in the attainment demonstration, etc. used in the projections. The Table of Contents of Supplement II-02 identifies where each sector is documented.

(1) Ambient Data

Because the exceedances of the PM_{10} standard only occur during winter inversion periods in Utah County, it is appropriate to look at winter seasons to determine the controls which may be necessary to reduce ambient PM_{10} concentrations to levels which are below the standard of 150 :g/m^3.

LINDON

Figure 9.A.1 shows the ambient PM_{10} concentrations measured at the Lindon monitoring station. As shown, the PM_{10} standard is exceeded in Lindon. Data from the most recent 24-month period (April, 1988, through March, 1990) will be used in the determination of the Lindon design value. There are no exceedances in the January-April, 1990 period.

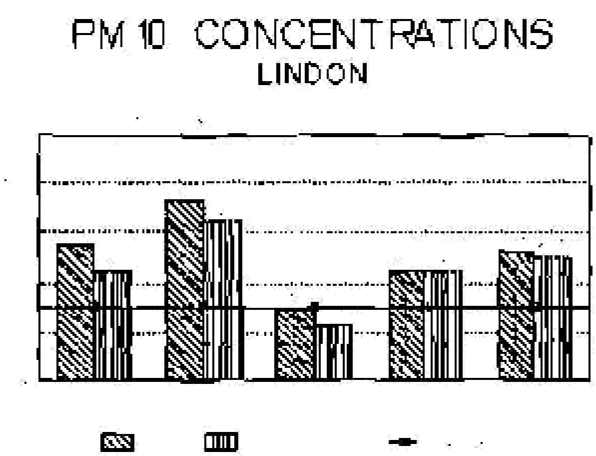


Figure 9A.1

NORTH PROVO

Figure 9.A.2 shows the ambient PM_{10} concentrations which were measured at the North Provo monitoring station. As can be seen, the standard for PM_{10} is exceeded in North Provo. Data from the most recent 24-month period (April, 1988, through March, 1990) will be used in the determination of the design value for the North Provo monitoring site. There are no exceedances in the January-April, 1990 period.

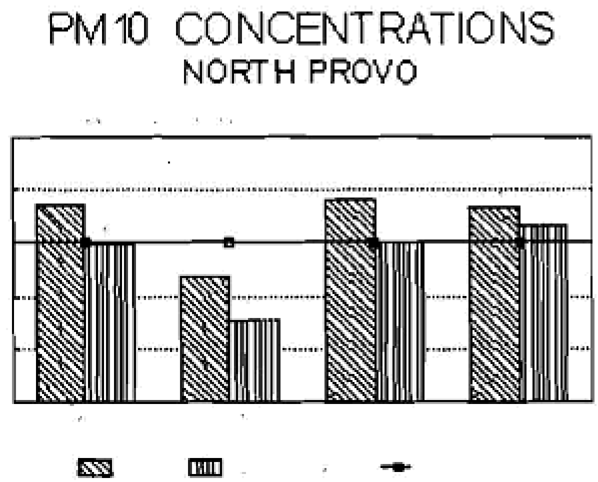


Figure 9.A.2

WEST OREM

Collection of PM_{10} data began at the West Orem monitoring site in October of 1988, and a complete year of data has since been collected. Figure 9.A.3 shows a summary of the ambient PM_{10} concentrations which were measured in West Orem. Data from the 12-month period from January through December of 1989 is used to allow the consideration of data from two separate winter seasons in the determination of the design value for West Orem. This will improve the reliability of this plan.

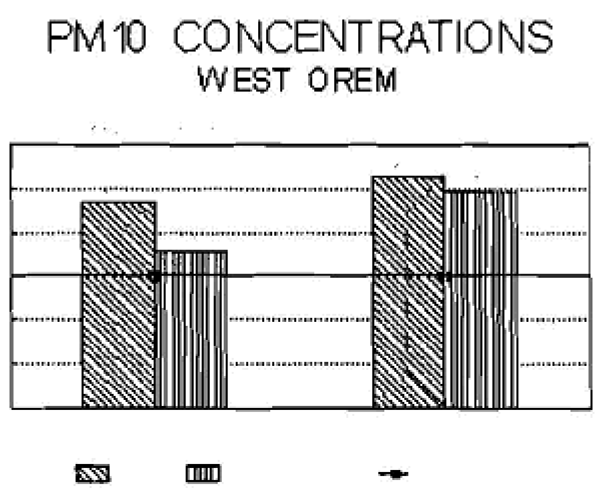


Figure 9.A.3

(2) Design Value Determination:

The design value is the PM_{10} concentration that becomes the reference point from which emissions of PM_{10} must be reduced in order to demonstrate attainment of the NAAQS at each monitoring site where violations of the NAAQS occur. As shown above, the Bureau of Air Quality is required to develop an independent design value for each of the monitoring sites in Utah County (i.e., Lindon, North Provo, and West Orem).

Because ambient monitoring data may not be collected each day or may not be collected at the point of highest concentration where the public has access, EPA guidance for PM_{10} SIP preparation normally requires the use of computer modeling to determine the design value. Computer modeling may also be used to verify that the observed pollution levels were the highest which could occur in the area under "worse case" meteorological conditions. If the model indicates that levels higher than those observed might occur, then those modeled values must be used to determine the design value.

One method of determining the design value is the application of dispersion modeling using the emission rates which sources of particulate matter are legally allowed to emit. In many cases the allowed emission rate may be significantly different than the actual emission rate of sources operating normally. Considerable time and effort was spent by the Bureau of Air Quality in calibrating the computer model recommended by EPA to match the monitored data, and modeling the allowed emission rates. The Bureau was allowing wind speeds to approach 0.2 meters per second to simulate winter inversion conditions since violations of the NAAQS routinely occur under such conditions. This technique showed very good agreement between model predictions, chemical mass balance (CMB) source apportionment analysis, and measured ambient PM_{10} concentrations, but the wind speeds which were used were below the EPA modeling requirements of one meter per second. As the process neared completion, EPA determined that the modeling protocol the Bureau was using did not meet the modeling guideline requirements, and EPA required the use of other methods to determine the design value.

EPA's disapproval of the dispersion model made it necessary to use actual measured PM_{10} concentrations to determine the design values. EPA's guidance on determining a design value using measured concentrations requires that the data record used in developing the design value should be a period when point source and area source emission rates are relatively constant and indicative of the usual condition. Since Geneva Steel was closed from August 1986 through September of 1987, and was in a "start-up" mode until March, 1988, the entire data record cannot be used to determine appropriate design values. Geneva Steel is the major Utah County point source of primary PM_{10} particulate and a substantial point source of gaseous sulfur and nitrogen emissions which become secondary PM_{10} particulate. In addition to the concerns presented by the closure of the steel mill, a concern exists that some components of the secondary PM_{10} particles, primarily the nitrates, may have been lost through sublimation from the ambient monitoring filters used to characterize PM_{10} concentrations in the early PM_{10} monitoring efforts. These two concerns dictate that the most recent data be used in determining the design values.

In using the most recent data we must be sure that one of the major sources, Geneva Steel, was operating at their normal capacity in order to have a valid data set. Figure 9.A.4 shows Geneva's production rate since they began operation in September of 1987. As can be seen, the plant was not in full production by December of that year, and discussions with the company have indicated that the plant was in the "start-up" mode until March, 1988; therefore, ambient PM10 data collected since April of 1988 can be used in determining the design value.

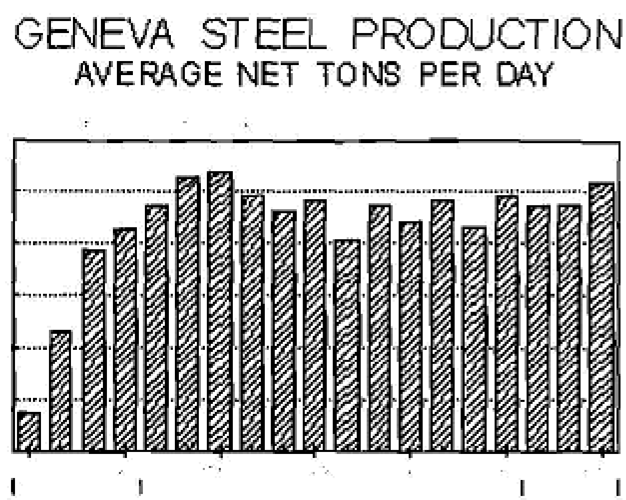


Figure 9.A.4

To ensure that each season of the year is represented by the data used in determining the design value, EPA requires the use of complete discrete 12-month data sets or sets which are multiples of 12-month periods.

In using the actual ambient data in determining the design value, the number of days of valid data collected is very important because some days of data may be missing which could have shown a violation of the PM_{10} standard had data been collected for that day. To assist in addressing this problem, EPA's Guideline Document contains a look-up table to be used in determining the design value if ambient monitoring data is used. Table 9.A.2 is a copy of the look-up table.

ESTIMATION OF PM_{10} DESIGN CONCENTRATIONS

NUMBER OF DAILY VALUES	DATA POINT USED FOR DESIGN CONCENTRATION
< 347	Highest Value
348 - 695	Second Highest Value
696 - 1042	Third Highest Value
1043 - 1096	Fourth Highest Value

Table 9.A.2

LINDON

Figure 9.A.5 shows a summary of the PM_{10} data collected at the Lindon monitoring station during the period from April, 1988, through March, 1990. The total number of days of data available during that period is 666 which is in the range of Table 9.A.2 which allows the use of the second highest observed concentration as the design value. The second highest value is 254 :g/m^3 which was measured on February 18, 1989, and is the design value for the Lindon monitor.

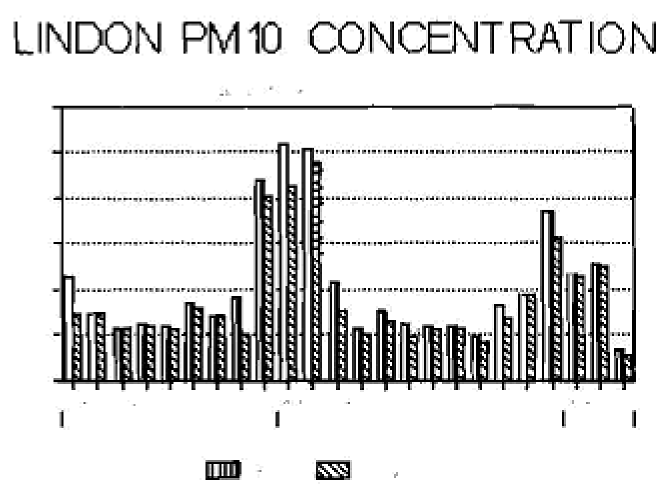


Figure 9.A.5

NORTH PROVO

Figure 9.A.6 shows a summary of the PM_{10} data collected at the North Provo monitoring station during the period from April, 1988, through March, 1990. The total number of days of data available during this monitoring period is 226. This number is less than 347 in Table 9.A.2, indicating that the highest value is to be used as the design value. The highest value is 191 :g/m^3 which was measured on January 28, 1988, and is the design value for the North Provo monitor.

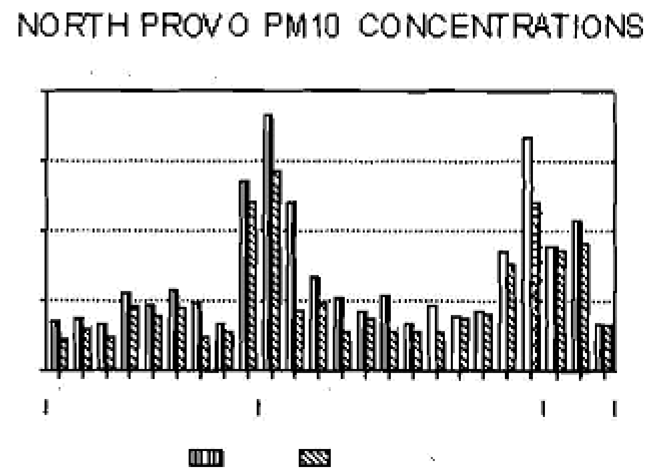


Figure 9.A.6

WEST OREM

PM_{10} Data collection began at West Orem in October, 1988, and a complete year of data has been collected. Figure 9.A.7 shows a summary of the PM_{10} data collected at West Orem from January through December, 1989. The number of days of data that were collected at the West Orem Station during the discrete 12-month period from January 1 through December 31, 1989 is 339, which is in the "less than 347" category in Table 9.A.2 above. Therefore, the highest value should be used as the design value. The highest value at West Orem is 263 :g/m3 which was measured on February 17, 1989 and is the design value for West Orem.

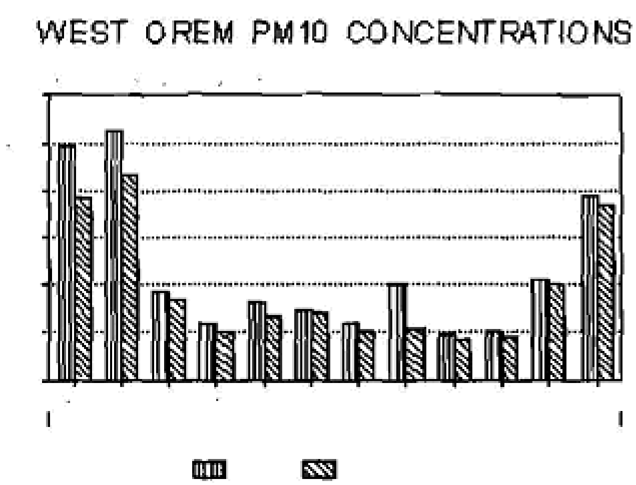


Figure 9.A.7

UTAH COUNTY NONATTAINMENT AREA

EPA requires that the highest design value in a PM_{10} nonattainment area be used in determining the amount of reduction that is necessary to attain the standard, and that the plan demonstrate attainment at all monitoring sites on all days which violate the standard. Since 263 :g/m^3 is 113 :g/m^3 above the standard, a 43% reduction of PM_{10}

emissions is necessary in the nonattainment area (i.e., [113/263] x 100) to attain the standard. Knowing the amount of reduction that is needed is essential in determining the control strategies that must be implemented to achieve that reduction.

(3) Source Apportionment Methodology:

UP-DOWN-UP ANALYSIS

A review of the Lindon PM_{10} monitoring data displayed graphically in Figures 9.A.8 and 9.A.9 indicates a major difference in data for the winter of 1986-87. Figure 9.A.8 shows that the number of violations of the standard was significantly less (0 vs. 10-22) and Figure 9.A.9 shows there was also a significant difference in the average concentration of the ten highest measured values (89 :g/m3 vs. 200+ :g/m3).

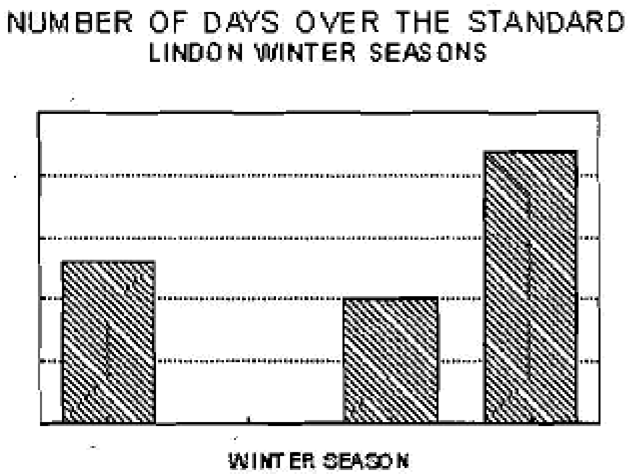


Figure 9.A.8

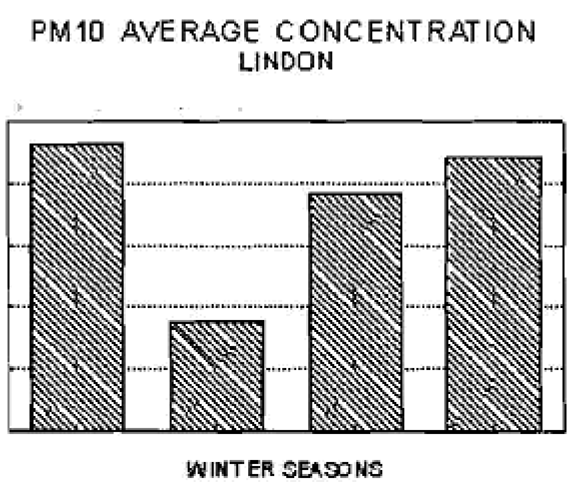


Figure 9.A.9

A possible explanation for this difference is that Geneva Steel was closed from August of 1986 through September of 1987. Further analysis of the past four winter seasons shows some interesting comparisons. The average of the ten highest concentrations measured during the winter of 1985-86, when Geneva was operating, was 231 :g/m3. The following winter, 1986-87, when Geneva was closed, the average was 89 :g/m3 which represented a decrease of 61%. The averages of the ten highest concentrations for the winters of 1987-88 and 1988-89, when Geneva was back in operation, were 192 :g/m3 and 220 :g/m3, respectively. This means that within two years of the reopening of Geneva, ambient PM_{10} concentrations had returned to 95% of what they were before the plant closed.

As expected, some of the emissions from a steel mill contain iron. Iron can be used as an indication of a steel mill's impact at a monitoring site. Chemical analysis has been performed on a number of filters from the Lindon monitor. The filters were selected for analysis based on whether they were among the highest values measured and whether filters from other monitoring stations were available to help characterize the polluted air mass. Iron is one of the elements for which the filters were analyzed. As shown in Figures 9.A.10 and 9.A.11, the average iron concentration from the chemical analysis of filters representing the highest concentrations observed during the winter of 1985-86 is 6.64 :g/m^3 and the average percent concentration of iron in the samples is 2.7.

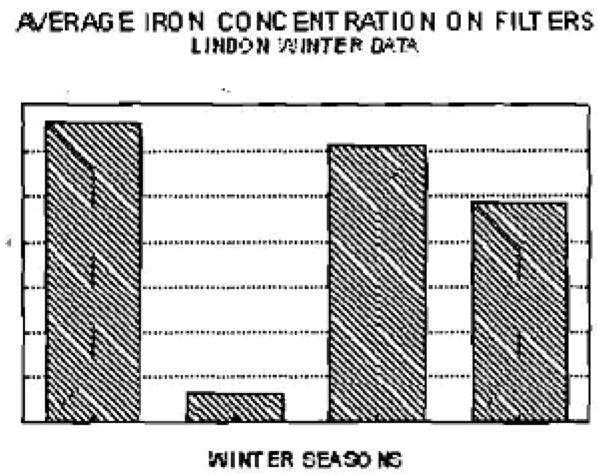


Figure 9.A.10

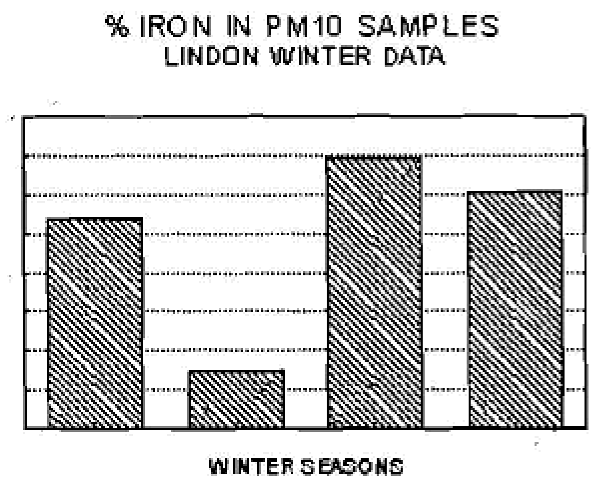


Figure 9.A.11

The average of 11 filters analyzed for the winter of 1986-87 is 0.64 :g/m^3 and the average percent iron in the samples is 0.75%. This information indicates that there was a 90% decrease in the iron concentrations and a 72% decrease in the percent concentration of iron in the samples during the period when Geneva was closed.

Since Geneva has resumed operation, the average concentration of iron for the filters which have been analyzed for the winter of 1987-88 is 6.11 :g/m^3 and the average percent concentration of iron in the samples is 3.46. For the winter of 1988-89, the average iron concentration is 4.88 :g/m^3 and the average percent concentration of iron is 3.02. This is a difference of 90% and 87% respectively in iron concentrations and a difference of 78% and 75% in the percent iron in the samples.

In making this analysis, other data has been reviewed to assure that all other conditions remained approximately the same during the period of observation. A review of the meteorological data suggests that the winter of 1986-87 was slightly warmer than normal, which implies that the use of residential solid fuel burners may have been reduced, which would result in a slight overstatement of the contribution of the mill to the ambient concentrations of PM_{10}. Even in view of the warmer winter, this up-down-up review strongly suggests that the impact of the Geneva steel mill at the Lindon monitoring station is greater than 50%. This review also suggests that conditions have not improved over the past two winter seasons. A weakness of this approach is that it is unable to provide information about other sources of PM_{10} in Utah County and the impact that they may have on the Lindon monitor. However, the closure of the steel mill provided the State with an opportunity to determine the relative impact of a major industrial source on ambient PM_{10} concentrations.

CMB APPORTIONMENT

Apportionment of PM_{10} impacts to individual major contributing sources was performed with the Chemical Mass Balance (CMB) receptor model. Two independent receptor modeling techniques were used to gain the most confidence in source apportionment contribution estimates.

The first technique was developed from the data collected when Geneva Steel was not operating. The period when Geneva Steel did not operate provided very valuable data on the chemical make-up of the ambient air without steel plant contamination. When Geneva Steel operated, there is a noticeable difference in the filter chemical "make-up". By methods of subtracting out the influence of the background chemical profiles, a composite Geneva steel profile was developed. The CMB model was performed on this Geneva composite profile and was used as the preliminary technique to apportion Geneva Steel.

The second technique to apportion PM_{10} was to use specific Geneva Steel source profiles collected by NEA, Inc., prior to June, 1989. Geneva Steel hired NEA to collect specific process profiles at Geneva, and to perform source apportionment using this data. The Bureau also performed CMB modeling using these source profiles as a corroborative technique to the first "up/down" CMB modeling method.

Comparisons using the first and second techniques for the winter of 1987/88 shows that the source contribution estimates from Geneva were in close agreement (56% by the up/down method and 50% by using NEA profiles). The up/down technique had about 6% more apportioned to Geneva Steel, because of the differences between the winter when Geneva Steel was not operating (warmer) and when Geneva Steel was operating (colder). The up/down technique is considered to be a level I analysis, which is the easiest and requires the least data. The second technique, using specific Geneva Steel source profiles, is considered a level II analysis. The level II analysis is preferred over a level I analysis. Only the level II analysis was performed for the winter of 1988/89, so no comparisons are available using the up/down technique with the source apportionment contained in this SIP.

A third technique, the development of a micro-inventory, was used to corroborate the first and second techniques and the level II analysis. The micro-inventory shows agreement with the previous techniques, and is contained in the technical support document.

As previously discussed, a dispersion modeling analysis was performed by the Bureau to help reconcile the CMB modeling results with actual emissions and meteorology. A technique was developed by the Bureau to allow for accurate model predictions in light winds. This technique employed use of meteorological data which was more accurate than data available from the National Weather Service. This technique showed very good agreement between model predictions, CMB source contributions and measured ambient PM_{10} concentrations. After long discussions with EPA on this technique, it was finally disapproved by EPA for use in the PM_{10} SIP and, therefore, could not be used in this analysis.

INVENTORY

Table IX.A.3 on the following two pages contains a base year and 2003 attainment inventory for Utah County. To obtain the vehicular emissions, MOBILE6 was run in order to obtain a fleet emission factor for both the base year of 1989, and for future years as the fleet turns over with newer "low NOx" vehicles replacing older "high NOx" vehicles. NOx control applied to the control strategy reflects the percentage of decrease in the emission factor relative to the base year factor of 1989 as well as any concurrent changes in vmt or vehicle speed. A detailed mobile source emissions inventory is contained in Supplement II-02 to the Technical Support Document for this PM10 SIP. The calculations to establish these inventories are contained in Supplement II-02 of the Technical Support Document.

UTAH STATE DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY
PM 10 SIP
Winter of 88/89 Emissions Inventory

Site: Utah County
Period: Highest Days 1988/89
Date: 6/18/02

(1) Area Source Emissions: In Tons per Day (for January 1989)

Vehicular	PM 10	SO2	NOx	Total
Unleaded	0.143	0.294	7.245	7.7
Leaded	0.234	0.473	11.721	12.4
Diesel	0.023	0.043	0.913	1.0
Road Dust - baseline	3.010	0.0	0.0	3.0
Road Salting	0.3	0.0	0.0	0.3
Break Wear	0.0	0.0	0.0	0.0
Subtotal:	3.71	0.81	19.88	24.40
Area Sources:				
Wood Burning	2.70	0.04	0.22	2.96
Coal Burning	0.05	0.07	0.07	0.19
Natural Gas	0.24	0.02	3.00	3.26
Oil, LPG, and Other	0.02	0.18	0.08	0.28
planes, trains, & off-rd.	0.06	0.08	1.13	1.27
Subtotal:	3.07	0.39	4.50	7.96

Composite Automobile Profile Breakout:

Fuel Type	Conditions	% in Profile
Leaded	cold start	5.5
Leaded	hot, normal	25.3
Unleaded	cold start	3.4
Unleaded	hot, normal	15.6
Diesel	cold start	9.0
Diesel	hot, normal	41.2
Total		100.0

(2) Point Source Inventory:

Annual Inventory for 1988 — In Tons per Year (right-hand columns)

Company Name	PM 10	SO2	NOx	Total	Conversion Factor_ annual to monthly found in this collumn	PM 10 (Annual)	SO2 (Annual)	NOx (Annual)	Total (Annual)
BYU	0.3600	1.7500	1.0500	3.1600					
Consolidated Red Mix	0.0400	0.0090	0.0820	0.1310					
General Refractories	0.3578	0.2503	0.6350	1.2431					
Geneva Rock	0.0250	0.0101	0.0965	0.1316					
Heckett	0.5128	0.0178	0.1811	0.7117					
Geneva Nitrogen (LaRoche)	0.2800	0.0000	3.2080	3.4880					
Lehi Cogen	0.0000	0.0000	0.0000	0.0000					
Pacific States Cast Iron Pipe	0.0850	0.0452	0.1299	0.2601					
Provo City Power	0.0093	0.0025	0.2540	0.2658					
Reilly Tar	0.0016	0.0001	0.0202	0.0219					
Springville City Power	0.0009	0.0023	0.1720	0.1752					
UP&L, Hale	0.0000	0.0000	0.0000	0.0000					
Westroc Highland	0.0000	0.0000	0.0000	0.0000					
Westroc Pleasent Grove	0.0138	0.0022	0.0227	0.0387					
Geneva Other	0.8655	0.0000	0.0000	0.8655	365	316			
Subtotal:	2.5517	2.0895	5.8514	10.4926					
Geneva Steel Processes:									
Coke Plant	2.0107	21.5973		23.6079	365	734	7,883		8,617
Open Hearth (Q-BOP)	0.6932			0.6932	365	253			253
Blast Furnace	0.9447			0.9447	365	345			345
Sinter Plant	0.3781			0.3781	365	138			138
Secondary Sulfate		3.1616		3.1616	365		1,154		1,154
Secondary Nitrate			12.5945	12.5945	365			4,597	4,597
Geneva Subtotal:	4.0266	24.7589	12.5945	41.3800 42.2455		1,470	9,037	4,597	15,104
Point Source Total:	6.5783	26.8484	18.4459	51.8726					
(3) Grand Totals (all sources):	13.3583	28.0484	42.8259	84.2326					

(4) Percent Breakout:

	PM 10	SO2	NOx	Total
Vehicular	27.8%	2.9%	46.4%	29.0%
Area Sources	23.0%	1.4%	10.5%	9.5%
Geneva Steel	36.6%	88.3%	29.4%	50.2%
Other Point Sources	12.6%	7.4%	13.7%	11.4%
Sum	100.0%	100.0%	100.0%	100.0%

TABLE IX.A.3 (page 1 of 2)

UTAH STATE DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY
PM10 SIP
Control Strategy Worksheet

Site:	Utah County	Note: Any name changes to industrial sources since 1989 are reflected here on this page, but not in the baseline (Winter 88/89) inventory on the previous page
Period:	Highest Days 1988/89	
Date:	6/18/02	
Projection:	2003	Inventory Data to Demonstrate Control

	Post - SIP Allowable Inventory In Tons per Day				Baseline Inventory for 1989 In Tons per Day			
	PM10	SO2	NOx	Total	PM10	SO2	NOx	Total
BYU	0.0434	0.0019	1.0386	1.0840	0.3600	1.7500	1.0500	3.1600
Fifteen Fifty Associates	0.0345	0.0071	0.0671	0.1088	0.0400	0.0090	0.0820	0.1310
Utah Refractories	0.1564	0.0778	0.3689	0.6030	0.3578	0.2503	0.6350	1.2431
Geneva Rock	0.6035	0.5181	0.7365	1.8581	0.0250	0.0101	0.0965	0.1316
Heckett	0.3733	0.0162	0.1679	0.5574	0.5128	0.0178	0.1811	0.7117
Geneva Nitrogen (LaRoch	0.3154	0.0000	0.6475	0.9629	0.2800	0.0000	3.2080	3.4880
Lehi Cogen	0.0053	0.0176	0.8123	0.8352	0.0000	0.0000	0.0000	0.0000
Pacific States Cast Iron Pi	0.1582	0.0604	0.2953	0.5139	0.0850	0.0452	0.1299	0.2601
Provo City Power	0.0837	0.0182	2.4480	2.5499	0.0093	0.0025	0.2540	0.2658
Reily Industries	0.0333	0.6300	0.3360	0.9993	0.0016	0.0001	0.0202	0.0219
Springville City Power	0.0209	0.0497	1.6875	1.7581	0.0009	0.0023	0.1720	0.1752
Pacificorp, Hale	0.0326	0.0038	2.1570	2.1934	0.0000	0.0000	0.0000	0.0000
Westroc, Highland	0.1757	0.0080	0.0844	0.2681	0.0000	0.0000	0.0000	0.0000
Westroc, Pleasent Grove	0.0564	0.0134	0.1321	0.2019	0.0138	0.0022	0.0227	0.0387
Geneva Other	1.1507			1.1507	0.8655	0.0000	0.0000	0.8655
Subtotal:	3.2432	1.4225	10.9790	15.6447	2.5517	2.0895	5.8514	10.4926
Geneva Steel Processes:								
Coke Gas Combustion	1.3463	1.2463		2.5926	2.0107	21.5973	0.0000	23.6079
Open Hearth (Q-BOP)	0.5627			0.5627	0.6932	0.0000	0.0000	0.6932
Blast Furnace	1.4616			1.4616	0.9447	0.0000	0.0000	0.9447
Sinter Plant	0.2767			0.2767	0.3781	0.0000	0.0000	0.3781
Secondary Sulfate		2.7244		2.7244	0.0000	3.1616	0.0000	3.1616
Secondary Nitrate			11.6005	11.6005	0.0000	0.0000	12.5945	12.5945
Geneva Subtotal:	3.6473	3.9707	11.6005	19.2186	4.0266	24.7589	12.5945	41.3800
				20.3693				42.2455
Area Sources:								
Wood Burning	3.87	0.06	0.32	4.25	2.70	0.04	0.22	2.96
Coal Burning	0.07	0.10	0.10	0.27	0.05	0.07	0.07	0.19
Natural Gas	0.34	0.02	4.31	4.67	0.24	0.02	3.00	3.26
Oil, LPG, and Other	0.02	0.26	0.12	0.40	0.02	0.18	0.08	0.28
planes, trains, & off-rd.	0.08	0.08	1.07	1.23	0.06	0.08	1.13	1.27
Subtotal:	4.38	0.52	5.92	10.82	3.07	0.39	4.50	7.96
Mobile Sources:								
Tailpipe PM10	0.34			0.34	0.40			0.40
Tire Wear	0.08			0.08	0.04			0.04
Re-entrained Road Dust	6.15			6.15	3.27			3.27
SO2		0.93		0.93		0.81		0.81
NOx			20.35	20.35			19.88	19.88
Subtotal:	6.57	0.93	20.35	27.85	3.71	0.81	19.88	24.40

TABLE IX.A.3 (Page 2 of 2)

(4) MONITORING SITE SOURCE APPORTIONMENT AND ATTAINMENT DEMONSTRATION

LINDON

DISTRIBUTION OF EXCEEDANCES

STATION	YEAR	JAN	FEB	MAR	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
LINDON	85			0	0	0	0	0	0	0	0	0	7	7
LINDON	86	6	0	0	0	0	0	0	0	0	0	0	0	6
LINDON	87	0	0	0	0	0	0	0	0	0	0	0	0	0
LINDON	88	5	5	0	0	0	0	0	0	0	0	0	6	16
LINDON	89	11	7	0	0	0	0	0	0	0	0	0	2	20
LINDON	90	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH PV	86	1	0	0	0	0	0	0	0	0	0	0	0	1
NORTH PV	87	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH PV	88	1	1	0	0	0	0	0	0	0	0	0	0	2
NORTH PV	89	1	0	0	0	0	0	0	0	0	0	0	1	2
NORTH PV	90	0	0	0	0	0	0	0	0	0	0	0	0	0
WEST OREM	88										0	0	3	3
WEST OREM	89	7	6	0	0	0	0	0	0	0	0	0	2	15
WEST OREM	90	0	0	0	0	0	0	0	0	0	0	0	0	0
SALT LAKE	87							0	0	0	0	0	0	0
SALT LAKE	88	1	0	0	0	0	0	0	0	1	0	0	1	3
SALT LAKE	89	2	1	0	0	0	0	0	0	0	0	0	0	3
SALT LAKE	90	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SL	85										0	0	1	1
NORTH SL	86	1	0	0	0	1	1	0	0	0	0	0	0	3
NORTH SL	87	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SL	88	1	1	0	1	1	0	0	0	0	0	0	3	7
NORTH SL	89	2	1	0	0	0	0	0	0	0	0	0	0	3
NORTH SL	90	0	0	0	0	0	0	0	0	0	0	0	0	0
AMC	89	5	1	0	0	0	0	0	0	0	0	0	1	7
AMC	90	0	0	0	0	0	0	0	0	0	0	0	0	0
MAGNA	85						1	1	1	0	0	0	0	3
MAGNA	86	0	0	0	0	1	0	2	0	0	0	0	0	3
MAGNA	87	0	0	0	1	0	1	0	0	0	0	0	0	2
MAGNA	88	0	0	1	1	0	0	0	0	0	0	0	0	2
MAGNA	89	0	0	0	0	0	0	0	0	0	0	0	0	0
MAGNA	90	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE 9.A.1

Source Apportionment

Figure IX.A.12 graphically demonstrates the source apportionment data contained on Table IX.A.4 on the following page and shows the contribution which the summarized components made to the overall concentration of PM10 at the Lindon monitoring site on February 18, 1989, which is the design day for the Lindon site.

Attainment Demonstration

Tables IX.A.4 and IX.A.5a and b show how the control strategies will reduce the PM10 concentrations at the Lindon site to no greater than 142.9 µg/m3 in 2002 and 2003. MOBILE6 projections using projected new motor vehicle control program NOx emission factors indicate there will be ample reduction from the new program to maintain ambient levels below the standard. Table IX.A.5.a demonstrates that the control strategies are effective in keeping the projected concentrations below 150 µg/m3 for the design day, and Table IX.A.5.b demonstrates that the control strategies are effective in keeping the projected concentrations below 150 µg/m3 for every episode day that was used in the analysis. This is the attainment demonstration for the Lindon site.

UTAH STATE DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY
PM10 SIP
Control Strategy Worksheet
Demonstration of Attainment (2003)

Site:	**Lindon**
Period:	Highest Days 1988/89
Date:	**6/18/02**
Projection:	2003

Source Category:	Percent Design Day Contribution:	Design Day Impact:	Additional Control:	Additional Growth:	Projected (2003) Attainment Impact:
(1) Geneva Steel Subtotal	58.11	147.59	65.1%	0.0%	51.47
Coke Stack	44.48	112.97	81.3%	0.0%	21.10
Open Hearth (Q-BOP)	4.83	12.28	18.8%	0.0%	9.97
Blast Furnace	0.00	0.00	-54.7%	0.0%	0.00
Sinter Plant	0.37	0.95	26.8%	0.0%	0.69
Secondary Sulfate	0.00	0.00	84.0%	0.0%	0.00
Secondary Nitrate	8.42	21.40	7.9%	0.0%	19.71
(2) Vehicle Subtotal	17.22	43.73			45.80
Composite Mobile Source	1.92	4.88	15.0%	0.0%	4.15
Re-entrained Road Dust	1.01	2.57	0.0%	88.2%	4.83
Road Salting	0.99	2.51	20.0%	11.9%	2.25
Secondary Sulfate	0.00	0.00	-14.8%	0.0%	0.00
Secondary Nitrate	13.30	33.77	-2.4%	0.0%	34.57
(3) Space Heating Sub-Total	19.27	48.95			17.66
Wood Burning	16.04	40.74	83.0%	0.0%	6.93
Coal Burning	0.03	0.08	83.0%	0.0%	0.01
Other Area Sources	0.19	0.48	0.0%	37.5%	0.66
Secondary Sulfate	0.00	0.00	0.0%	33.3%	0.00
Secondary Nitrate	3.01	7.65	0.0%	31.6%	10.06
(4) Other Point Sources Subt	5.41	13.73			23.47
B.Y.U. Power	0.21	0.53	87.9%	0.0%	0.06
Heckett	0.30	0.76	27.2%	0.0%	0.55
Geneva Nitrogen (LaRoche)	0.16	0.42	-12.6%	0.0%	0.47
U.P.& L Hale	0.00	0.00	Included in "Other Pt.Sources" Category		
Other Point Sources	0.82	2.08	-79.5%	0.0%	3.73
Secondary Sulfate	0.00	0.00	31.9%	0.0%	0.00
Secondary Nitrate	3.91	9.94	-87.6%	0.0%	18.65
TOTAL	100.00	254			138.40

Design Day Value:	254	ug/m^3	18-Feb-89
Max. Concentration Value:	138.4	ug/m^3	
Projection Year:	2003		

Point Source scaling factor:	0.5
Home Heat scaling factor:	0.1

TABLE IX.A.4

Lindon Monitoring Site
Demonstration of Attainment
Design Day / All Years
micrograms/cubic meter

Source Category:	2002	2003	Conformity 2010	2020
(1) Geneva Steel Subtotal	51.5	51.5	51.5	51.5
Coke Stack	21.1	21.1	21.1	21.1
Open Hearth (Q-BOP)	10.0	10.0	10.0	10.0
Blast Furnace	0.0	0.0	0.0	0.0
Sinter Plant	0.7	0.7	0.7	0.7
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	19.7	19.7	19.7	19.7
(2) Vehicle Subtotal	46.5	45.8	33.6	23.5
Composite Mobile Sources	4.3	4.1	3.8	4.5
Re-entrained Road Dust	4.7	4.8	5.8	7.7
Road Salting	2.2	2.3	2.4	2.5
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	35.4	34.6	21.7	8.7
(3) Other Area Sources	17.4	17.7	20.0	22.7
Wood Burning	6.9	6.9	6.9	6.9
Coal Burning	0.0	0.0	0.0	0.0
Other Area Sources	0.6	0.7	0.8	1.0
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	9.9	10.1	12.2	14.7
(4) Other Point Sources Subtotal	23.5	23.5	23.5	23.5
B.Y.U. Power	0.1	0.1	0.1	0.1
Heckett	0.6	0.6	0.6	0.6
Geneva Nitrogen (LaRoche)	0.5	0.5	0.5	0.5
U.P.& L. Hale				
Other Point Sources	3.7	3.7	3.7	3.7
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	18.7	18.7	18.7	18.7
Total	138.9	138.4	128.5	121.1

TABLE IX.A.5.a

LINDON MONITORING SITE
DEMONSTRATION OF ATTAINMENT
ALL DAYS / ALL YEARS
micrograms / cubic meter

Year \ Day	2-Dec-88	3-Dec-88	4-Dec-88	5-Dec-88	6-Dec-88	18-Dec-88	3-Jan-89
2002	98.5	117.4	135.4	104.5	86.5	95.2	105.4
2003	98.9	117.4	135.2	104.2	86.1	95.0	106.1
Conformity Only							
2010	98.8	113.3	127.8	99.1	81.3	90.2	108.1
2020	105.0	112.9	124.1	94.9	78.2	87.9	118.1

Year \ Day	17-Jan-89	18-Jan-89	19-Jan-89	20-Jan-89	21-Jan-89	27-Jan-89	28-Jan-89	29-Jan-89
2002	102.9	128.6	128.7	143.5	112.8	133.8	124.4	124.0
2003	103.5	129.2	128.8	142.9	112.3	134.5	124.2	123.7
Conformity Only								
2010	104.3	129.6	124.2	132.6	104.1	135.0	116.9	116.0
2020	112.0	138.4	124.2	123.3	96.8	145.1	113.6	111.9

Year \ Day	30-Jan-89	15-Feb-89	16-Feb-89	17-Feb-89	18-Feb-89	27-Dec-89	28-Dec-89
2002	130.2	90.4	92.7	133.6	138.9	99.8	125.6
2003	130.4	91.1	93.1	133.3	138.4	100.2	126.1
Conformity Only							
2010	127.4	93.6	93.4	125.7	128.5	99.8	125.6
2020	130.8	103.2	99.3	120.8	121.1	105.8	134.3

TABLE IX.A.5.b

WEST OREM

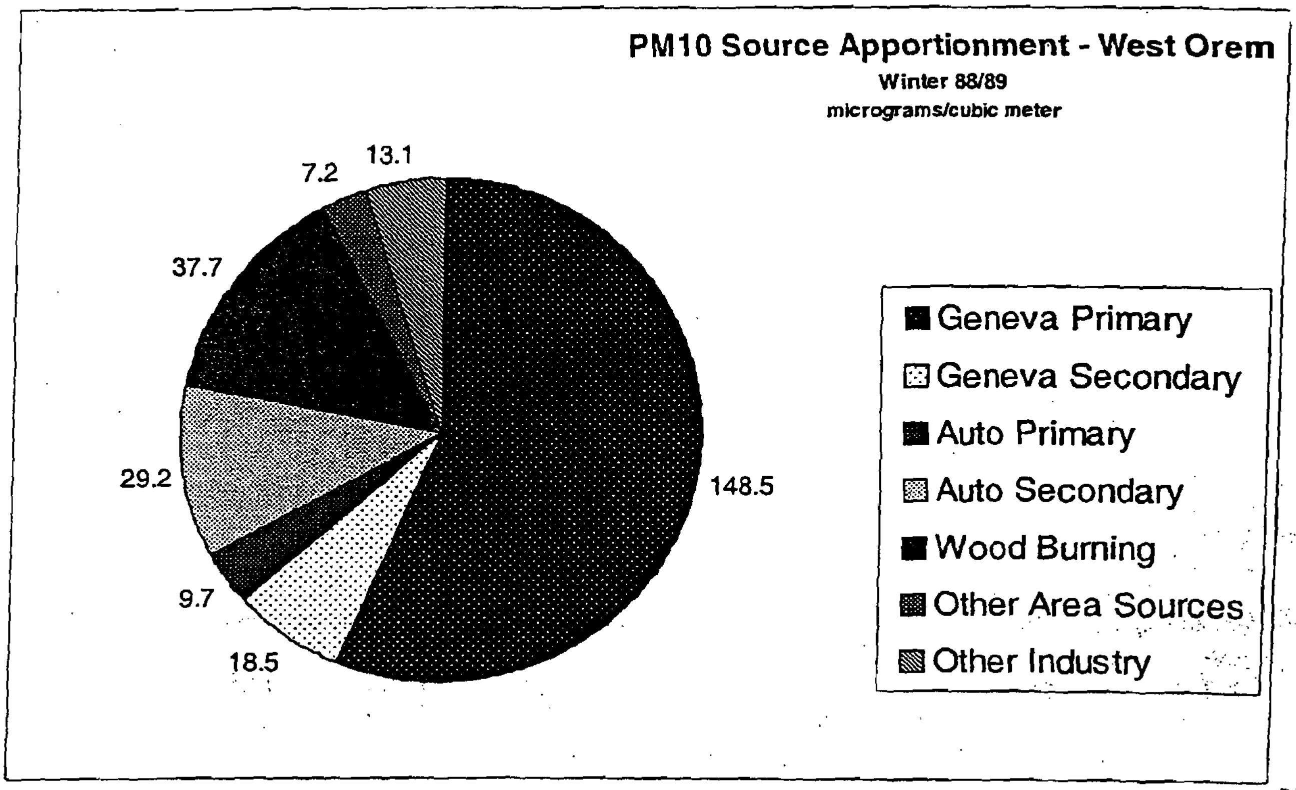


FIGURE IX.A.13

Source Apportionment

Figure IX.A.13 graphically demonstrates the source apportionment data detailed in Table IX.A.6 on the following page and shows the contribution which the summarized components made to the overall concentration of PM_{10} at the West Orem site.

Attainment Demonstration

Tables IX.A.6 and IX.A.7a and b show how the control strategies will reduce the PM10 concentrations at the West Orem monitoring station to no greater than 146.5 µg/m3 in 2002 and 2003. MOBILE6 projections using projected new motor vehicle control program NOx emission factors indicate there will be ample reduction from the new program to maintain ambient levels below the standard. Table IX.A.7.a demonstrates that the control strategies are effective in keeping the projected concentrations below 150 µg/m3 for the design day, and Table IX.A.7.b demonstrates that the control strategies are effective in keeping the projected concentrations below 150 µg/m3 for every episode day that was used in the analysis. This is the attainment demonstration for the West Orem monitoring site.

UTAH STATE DEPT. ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY
PM10 SIP
Control Strategy Worksheet

Site: West Orem
Period: Highest Days 1988/89
Date: 6/18/02
Projection: 2003

Source Category:	Percent Design Day Contribution:	Design Day Impact:	Additional Control:	Additional Growth:	Projected Attainment Impact:
(1) Geneva Steel Subtotal	63.30	167.0	63.7%	0.0%	61.65
Coke Stack	46.03	121.5	81.3%	0.0%	22.69
Open Hearth (Q-BOP)	10.01	26.4	18.8%	0.0%	21.44
Blast Furnace	0.00	0.0	-54.7%	0.0%	0.00
Sinter Plant	0.23	0.6	26.8%	0.0%	0.45
Secondary Sulfate	0.00	0.0	84.0%	0.0%	0.00
Secondary Nitrate	7.02	18.5	7.9%	0.0%	17.07
(2) Vehicle Subtotal	14.75	38.92			38.43
Composite Mobile Sources	1.46	3.9	15.0%	0.0%	3.29
Re-entrained Road Dust	0.00	0.0	0.0%	88.2%	0.00
Road Salting	2.20	5.8	20.0%	11.9%	5.20
Secondary Sulfate	0.00	0.0	-14.8%	0.0%	0.00
Secondary Nitrate	11.08	29.2	-2.4%	0.0%	29.94
(3) Space Heating Subtotal	17.00	44.9			15.75
Wood Burning	14.30	37.7	83.0%	0.0%	6.41
Coal Burning	0.03	0.1	83.0%	0.0%	0.01
Other Area Sources	0.17	0.4	0.0%	37.5%	0.61
Secondary Sulfate	0.00	0.0	0.0%	33.3%	0.00
Secondary Nitrate	2.51	6.6	0.0%	31.6%	8.71
(4) Other Point Sources Subtotc	4.95	13.1			21.82
B.Y.U. Power	0.24	0.6	87.9%	0.0%	0.08
Heckett	0.34	0.9	27.2%	0.0%	0.65
Geneva Nitrogen (LaRoche)	0.19	0.5	-12.6%	0.0%	0.55
U.P.&L. Hale	0.00	0.0	Included in "Other Pt Sources" Category		
Other Point Sources	0.93	2.4	-79.5%	0.0%	4.39
Secondary Sulfate	0.00	0.0	31.9%	0.0%	0.00
Secondary Nitrate	3.26	8.6	-87.6%	0.0%	16.15
TOTAL	100.00	263.9			137.65

Design Day Value: 263.9 ug/m^3 17-Feb-89

Max. Concentration Value: 145.8 ug/m^3

Projection Year: 2003

Point Source scaling factor: 0.5

Home Heat scaling factor: 0.1

TABLE IX.A.6

West Orem Monitoring Site
Demonstration of Attainment
Design Day / All Years
micrograms/cubic meter

Source Category:	2002	2003	Conformity 2010	2020
(1) Geneva Steel Subtotal	61.7	61.7	61.7	61.7
Coke Stack	22.7	22.7	22.7	22.7
Open Hearth (Q-BOP)	21.4	21.4	21.4	21.4
Blast Furnace	0.0	0.0	0.0	0.0
Sinter Plant	0.4	0.4	0.4	0.4
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	17.1	17.1	17.1	17.1
(2) Vehicle Subtotal	39.2	38.4	27.2	17.0
Composite Mobile Sources	3.4	3.3	3.0	3.6
Re-entrained Road Dust	0.0	0.0	0.0	0.0
Road Salting	5.2	5.2	5.5	5.9
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	30.6	29.9	18.8	7.5
(3) Space Heating Subtotal	15.6	15.8	17.7	20.1
Wood Burning	6.4	6.4	6.4	6.4
Coal Burning	0.0	0.0	0.0	0.0
Other Area Sources	0.6	0.6	0.8	0.9
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	8.5	8.7	10.6	12.8
(4) Other Point Sources Subtotal	21.8	21.8	21.8	21.8
B.Y.U. Power	0.1	0.1	0.1	0.1
Heckett	0.7	0.7	0.7	0.7
Geneva Nitrogen (LaRoche)	0.6	0.6	0.6	0.6
U.P.& L. Hale				
Other Point Sources	4.4	4.4	4.4	4.4
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	16.2	16.2	16.2	16.2
Total	138.2	137.7	128.5	120.6

TABLE IX.A.7.a

WEST OREM MONITORING SITE
DEMONSTRATION OF ATTAINMENT
ALL DAYS / ALL YEARS
micrograms/cubic meter

Day	19-Jan-89	21-Jan-89	27-Jan-89	28-Jan-89	29-Jan-89	30-Jan-89	10-Feb-89	15-Feb-89
Year								
2002	115.5	125.3	106.4	102.2	98.4	112.1	80.2	78.8
2003	115.5	124.7	106.5	101.9	98.2	112.4	80.0	79.4
Conformity Only								
2010	111.9	115.8	103.4	94.3	92.4	110.6	75.9	82.2
2020	113.4	108.2	105.3	89.3	89.7	115.8	72.4	91.5

Day	16-Feb-89	17-Feb-89	18-Feb-89	19-Feb-89	5-Dec-88	27-Dec-89	28-Dec-89
Year							
2002	100.3	138.2	146.5	110.7	110.1	135.3	116.5
2003	100.1	137.7	145.8	110.1	109.8	136.0	116.8
Conformity Only							
2010	95.9	128.5	133.0	100.4	104.5	136.4	114.8
2020	92.3	120.6	121.9	92.1	100.7	147.2	119.7

TABLE IX.A.7.b

NORTH PROVO

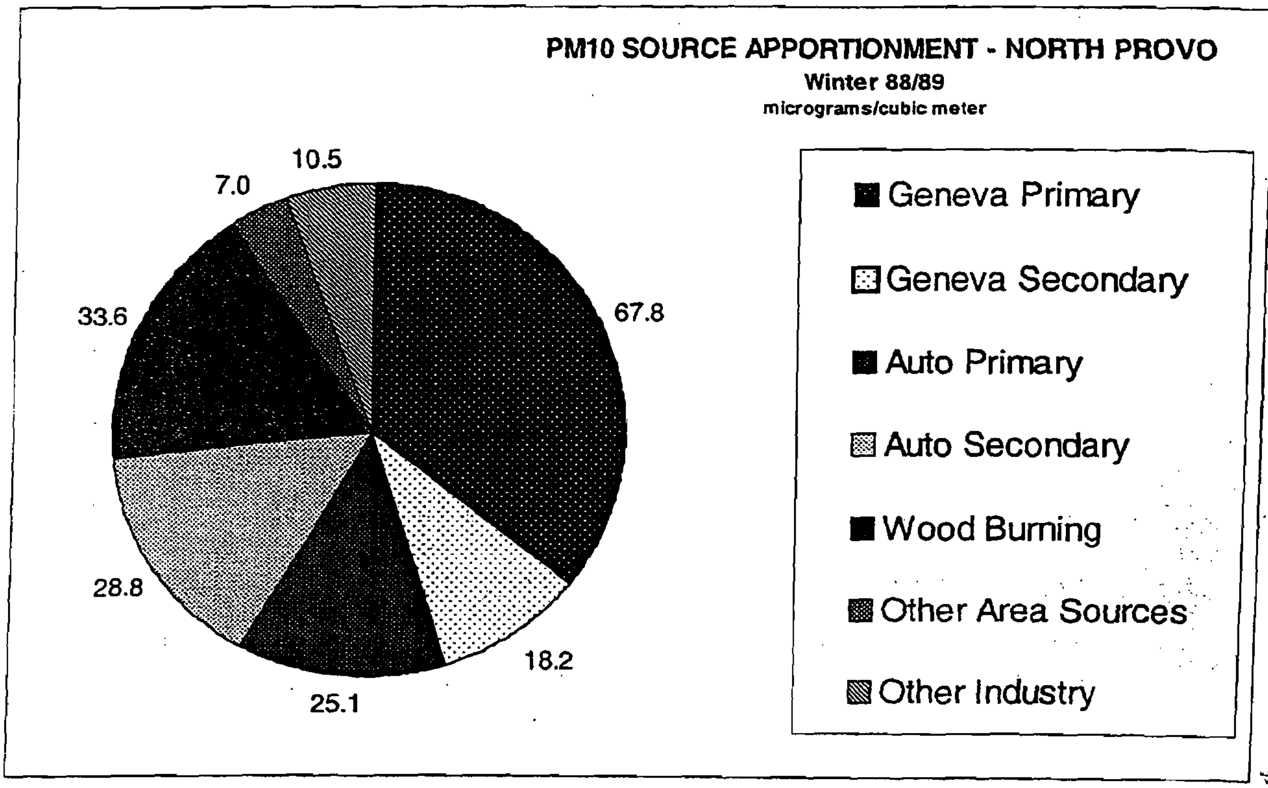


FIGURE IX.A.14

Source Apportionment

Figure IX.A.14 graphically demonstrates the source apportionment data detailed in Table IX.A.8 on the following page and shows the contribution which the summarized components made to the overall concentrations of PM_{10} at the North Provo monitoring site.

Attainment Demonstration

Tables IX.A.8 and IX.A.9a and b show how the control strategies will reduce the PM10 concentrations at the North Provo monitoring station to no greater than 135.1 µg/m3 in 2002 and 2003. Table IX.A.9.a demonstrates that the control strategies are effective in keeping the projected concentrations below 150 µg/m3 for the design day, and Table IX.A.9.b demonstrates that the control strategies are effective in keeping the projected concentrations below 150 µg/m3 for every episode day that was used in the analysis. This is the attainment demonstration for the North Provo monitoring site.

UTAH STATE DEPT. ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY
PM10 SIP
Control Strategy Worksheet

Site:	**North Provo**
Period:	Highest Days 1988/89
Date:	**6/18/02**
Projection:	2003

Source Category:	**Percent Design Day Contribution:**	**Design Day Impact:**	**Additional Control:**	**Additional Growth:**	**Projected Attainment Impact:**
(1) Geneva Steel Subtotal	45.04	86.0	55.0%	0.0%	38.69
Coke Stack	27.61	52.7	81.3%	0.0%	9.85
Open Hearth (Q-BOP)	6.73	12.9	18.8%	0.0%	10.44
Blast Furnace	0.00	0.0	-54.7%	0.0%	0.00
Sinter Plant	1.16	2.2	26.8%	0.0%	1.62
Secondary Sulfate	0.00	0.0	84.0%	0.0%	0.00
Secondary Nitrate	9.54	18.2	7.9%	0.0%	16.78
(2) Vehicle Subtotal	28.21	53.88			63.06
Composite Mobile Sources	3.62	6.9	15.0%	0.0%	5.87
Re-entrained Road Dust	6.07	11.6	0.0%	88.2%	21.82
Road Salting	3.46	6.6	20.0%	11.9%	5.92
Secondary Sulfate	0.00	0.0	-14.8%	0.0%	0.00
Secondary Nitrate	15.06	28.8	-2.4%	0.0%	29.44
(3) Space Heating Subtotal	21.25	40.6			14.84
Wood Burning	17.60	33.6	83.0%	0.0%	5.72
Coal Burning	0.03	0.1	83.0%	0.0%	0.01
Other Area Sources	0.21	0.4	0.0%	37.5%	0.55
Secondary Sulfate	0.00	0.0	0.0%	33.3%	0.00
Secondary Nitrate	3.41	6.5	0.0%	31.6%	8.57
(4) Other Point Sources Subtota	5.50	10.5			18.47
B.Y.U. Power	0.15	0.3	87.9%	0.0%	0.03
Heckett	0.21	0.4	27.2%	0.0%	0.30
Geneva Nitrogen (LaRoche)	0.12	0.2	-12.6%	0.0%	0.25
U.P.&L. Hale	0.00	0.0	Included in "Other Pt.Sources" Category		
Other Point Sources	0.58	1.1	-79.5%	0.0%	2.00
Secondary Sulfate	0.00	0.0	31.9%	0.0%	0.00
Secondary Nitrate	4.43	8.5	-87.6%	0.0%	15.89
TOTAL	100.00	191.0			135.06

Design Day Value:	191	ug/m^3	28-Jan-88
Max. Concentration Value:	135.1	ug/m^3	
Projection Year:	2003		

Point Source scaling factor:	0.5
Home Heat scaling factor:	0.1

TABLE IX.A.8

North Provo Monitoring Station
Demonstration of Attainment
Design Day / All Years
micrograms/cubic meter

Source Category:	2002	2003	Conformity 2010	2020
(1) Geneva Steel Subtotal	38.7	38.7	38.7	38.7
Coke Stack	9.9	9.9	9.9	9.9
Open Hearth (Q-BOP)	10.4	10.4	10.4	10.4
Blast Furnace	0.0	0.0	0.0	0.0
Sinter Plant	1.6	1.6	1.6	1.6
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	16.8	16.8	16.8	16.8
(2) Vehicle Subtotal	63.2	63.1	56.1	55.4
Composite Mobile Sources	6.0	5.9	5.4	6.4
Re-entrained Road Dust	21.2	21.8	26.0	34.9
Road Salting	5.9	5.9	6.2	6.7
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	30.1	29.4	18.4	7.4
(3) Space Heating Subtotal	14.7	14.8	16.8	19.1
Wood Burning	5.7	5.7	5.7	5.7
Coal Burning	0.0	0.0	0.0	0.0
Other Area Sources	0.5	0.5	0.7	0.8
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	8.4	8.6	10.4	12.6
(4) Other Point Sources Subtotal	18.5	18.5	18.5	18.5
B.Y.U. Power	0.0	0.0	0.0	0.0
Heckett	0.3	0.3	0.3	0.3
Geneva Nitrogen (LaRoche)	0.3	0.3	0.3	0.3
U.P.& L. Hale				
Other Point Sources	2.0	2.0	2.0	2.0
Secondary Sulfate	0.0	0.0	0.0	0.0
Secondary Nitrate	15.9	15.9	15.9	15.9
Total	135.0	135.1	130.0	131.7

TABLE IX.A.9.a

North Provo Monitoring Site
Demonstration of Attainment
All Days / All Years
micrograms / cubic meter

Day	4-Jan-88	28-Jan-88	6-Feb-88	27-Dec-89	28-Dec-89
Year					
2002	83.2	135.0	116.1	88.4	119.1
2003	82.8	135.1	116.9	88.9	119.3
Conformity Only					
2010	76.4	130.0	118.7	89.3	116.4
2020	71.5	131.7	130.7	97.3	121.7

TABLE IX.A.9.b

SECTION IX.A.4 SALT LAKE COUNTY - MAGNA

Figure IX.A.15 shows the ambient PM10 concentrations measured at the Magna monitoring station since 1985.

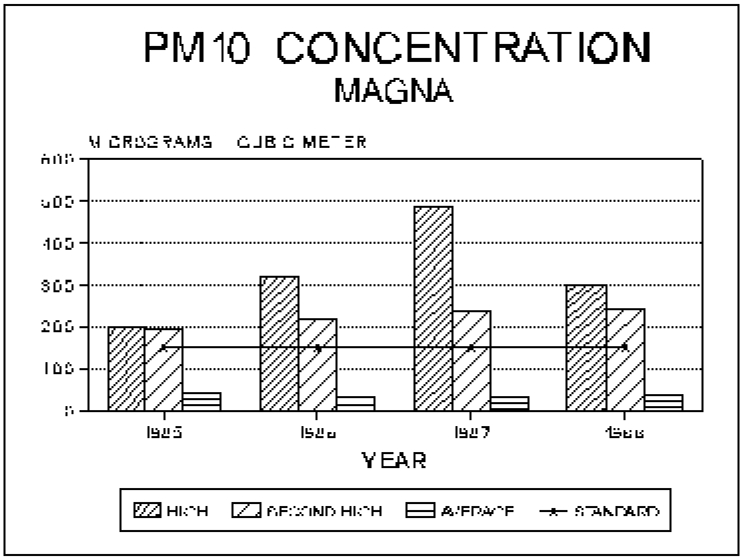


Figure IX.A.15.

(1) Design Value Determination

Based on the 724 observations in the three year period from 1987 through 1989, the look-up table contained in Table 9.A.2, the data in Table 9.A.10 below indicates that the design value for Magna in Salt Lake County is the third-high reading, or 304 micrograms/meter^3 (:g/m^3) as measured on March 27, 1988.

MAGNA PM10 MONITORING DATA

	1989	1988	1987	1986	1985
High 24 Hr. Avg.	107	304	487	320	197
Second High 24 Hr.	105	243	236	219	194
Third High 24 Hr.	103	131	104	179	170
Fourth High 24 Hr.	97	128	99	140	140
Number of days data	78	330	316	314	101

Table IX.A.10

(2) Source Apportionment

The violations of the PM_{10} standard in Magna were caused primarily by the blowing of tailings from the Kennecott tailings pond under certain meteorological conditions while the plant was shut down. This is confirmed by the meteorological data which is summarized in Table IX.A.11 below.

DATE	MEASURED CONCEN-TRATION	MAXIMUM WIND SPEED (MPH)	WIND DIRECTION (DEGREES)
6-24-85	170	15	308
7-30-85	197	18/11	150/309 WIND SHIFT
8-08-85	194	15/11	186/342 WIND SHIFT
5-21-86	179	23	322
7-04-86	320	19	333
7-16-86	219	21/18	150/347 WIND SHIFT
4-18-87	236	25	304
6-22-87	487	21	324
3-27-88	304	20	359
4-07-88	243	23	295

TABLE IX.A.11

SECTION IX.A.5 <u>SALT LAKE NONATTAINMENT AREA</u>

(1) Ambient Data

Because the exceedances of the PM_{10} standard only occur during winter inversion periods in Salt Lake and Davis Counties, except in those areas which are impacted by blowing tailings from the Kennecott tailings pond (i.e., Magna), it is appropriate to look at winter seasons to determine the controls which may be necessary to reduce ambient PM_{10} concentrations to levels which are below the standard of 150 µg/m^3.

NORTH SALT LAKE

Figure IX.A.16 shows the ambient PM_{10} concentrations measured at the North Salt Lake monitoring station. As shown, the PM_{10} standard is exceeded in North Salt Lake. These data will be used in the determination of the North Salt Lake design value.

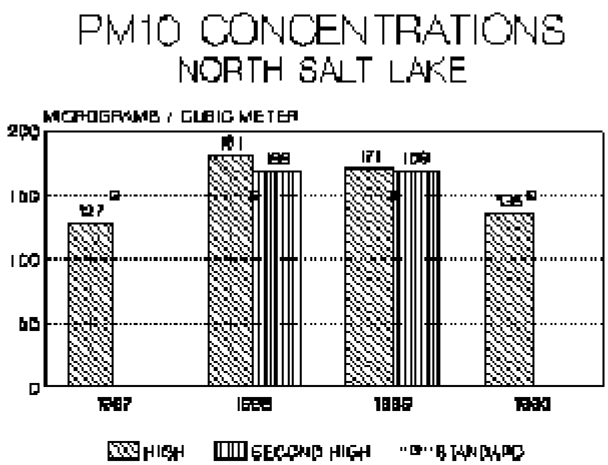


Figure IX.A.16

AIR MONITORING CENTER (AMC)

Figure IX.A.17 shows the ambient PM_{10} concentrations which were measured at the Air Monitoring Center in Salt Lake. As can be seen, the standard for PM_{10} is exceeded in Salt Lake City at the AMC. These data will be used in the determination of the design value for the AMC monitoring site.

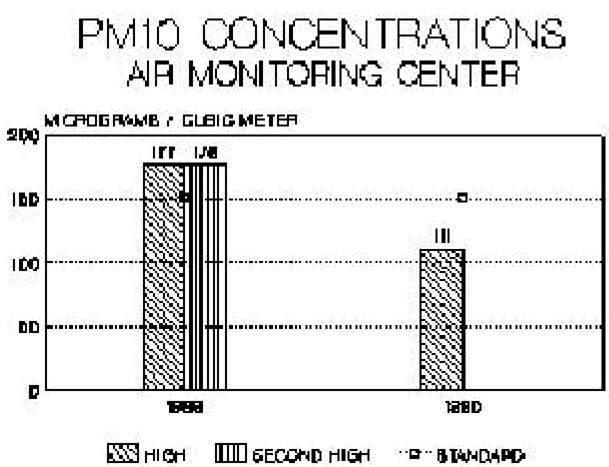


Figure IX.A.17

SALT LAKE

Figure IX.A.18 shows the ambient PM_{10} concentrations which are measured at the Salt Lake monitoring site. As can be seen, the standard for PM_{10} is exceeded in Salt Lake at the Salt Lake Monitoring Site. These data will be used to determine the design value for the Salt Lake monitoring site.

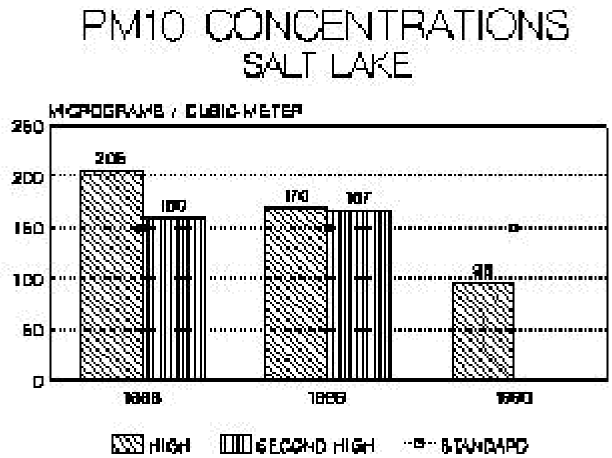


Figure IX.A.18

(2) Design Value Determination

The design value is the PM_{10} concentration that becomes the reference point from which emissions of PM_{10} must be reduced in order to demonstrate attainment of the NAAQS at each monitoring site where violations of the NAAQS occur. As shown above, the Bureau of Air Quality is required to develop an independent design value for each of the monitoring sites in the Salt Lake nonattainment Area where exceedances of the NAAQS have been observed (i.e., the North Salt Lake, the Salt Lake, and the AMC monitoring sites).

EPA's concerns with the performance of dispersion modeling in Salt Lake County made it necessary to use actual measured PM_{10} concentrations to determine the design values. EPA's guidance on determining a design value using measured concentrations requires that the data record used in developing the design value should be a period when point source and area source emission rates are relatively constant and indicative of the usual condition. The design values for the Salt Lake - Davis County nonattainment Area monitoring sites were determined by using the table lookup method. Table IX.A.12 lists the design values for each monitoring site in the Salt Lake - Davis County nonattainment Area. Using Table IX.A.2, the design value for the AMC and the Salt Lake monitoring sites were the highest observerd value. There were more than 900 observations at the North Salt Lake monitoring site which allowed the use of the third highest observed concentration as the design value.

SITE	**DESIGN VALUE**
AIR MONITORING CENTER	177 µg/m3
NORTH SALT LAKE	169 µg/m3
SALT LAKE	170 µg/m3

TABLE IX.A.12

EPA requires that the highest design value in a PM_{10} nonattainment area be used in determining the amount of reduction that is necessary to attain the standard, and that the plan demonstrate attainment at all monitoring sites on all days on which the NAAQS was exceeded but for which the observed concentration was less than the design value for that site. Since the 177 $\mu g/m^3$ at the Air Monitoring Center is 27 $\mu g/m^3$ above the standard, an 15% reduction of PM_{10} emissions is necessary in the nonattainment area (i.e., [27/177] x 100) to attain the standard. Knowing the amount of reduction that is needed is essential in determining the control strategies that must be implemented to achieve that reduction.

(3) Source Apportionment Methodology:

The problem of identifying which sources contribute to the PM_{10} violations measured along the Wasatch Front is a complicated one. The problems stem from the fact that a majority of what makes up the particulate measured on the filter is a result of chemical reactions which occur in the atmosphere. These pollutants which undergo chemical reactions are a result of gaseous emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). The gaseous emissions, called precursors, are being controlled as part of the strategy to reduce the excessive particulate measured in Salt Lake and Davis Counties. The problem is compounded by the presence of a large source of secondary PM_{10} emissions, Kennecott, more than 23 miles away on the other side of the valley from the monitors. Kennecott performed a tracer study in February, 1990 to determine if its emissions impact the monitoring sites. That study showed that tall stack and low level emissions do, indeed, impact the monitoring sites. Chemical Mass Balance (CMB) modeling indicates that primary PM_{10} emissions from the smelter contribute as much as 12 $\mu g/m^3$ at the Air Monitoring Center (on the 2nd high day). With the presence of primary emissions from the smelter, one can expect secondary PM_{10} to impact the monitor also, since the two components undergo similar transport and diffusion. It is assumed in the proposed control strategies adopted with this SIP that emissions from the tall stack impact the group I area.

The procedure of identifying contributing sources, called source apportionment, uses the EPA's latest recommended procedures. These procedures involve the use of two independent techniques for identifying the sources. By having agreement between the two techniques, a more confident source apportionment can be obtained.

The two techniques used involve the use of a receptor model, called the (CMB) model, and a micro-scale emissions inventory. The CMB model uses the chemical makeup of the measured particulate to trace back where the particulate came from. By knowing what the chemical makeup of each potential source is, this method can calculate what percent each source contributes to the particulate problem. The microinventory approach uses the amount of pollutant released by the sources to provide overall source category percent contributions.

Results from the CMB model are the main basis for source apportionment in this SIP. Source contribution estimates from the CMB model for vehicles, woodburning, and industry are compared to similar estimates using the micro-inventory approach. Inconsistencies in the source contributions must be reconciled before the source apportionment is considered adequate. The CMB and micro-inventory approtionment analysis and comparison results are discussed in detail in the Technical Support Document. A summary of the Salt Lake/Davis County inventory is contained in Table IX.A.13 on the following five pages.

UTAH STATE DEPARTMENT OF HEALTH
Division of Environmental Health
Bureau of Air Quality
PM10 S.I.P
Winter of 88/89 Emissions Inventory - Salt Lake & Davis Counties

(1) Area source emissions (Tons/Month)

	PM_{10}	SO_2	NO_x	TOTAL	Annual-> Winter Month Conversion Factor	1988 ACTUAL (Tons/Year) PM_{10}	SO_2	NO_x	Total
A> Vehicular									
Unleaded	9.3	23.5	262.5	295.3					
Leaded	15.1	38.1	425.5	478.7					
Diesel	51.8	157.6	693.6	903.0					
Roaddust	826.2	0.0	0.0	826.2					
Roadsanding	26.1	0.0	0.0	26.1					
Roadsalt	135.6	0.0	0.0	135.6					
Brake wear	36.7	0.0	0.0	36.7					
Sub-Total	1100.9	219.2	1381.6	2701.7					
B> Other transportation									
Trains	7.4	14.3	93.1	114.8	0.0833	88.4	172.1	1117.1	1377.6
Airplanes	6.8	9.5	79.8	96.0	0.0833	81.4	113.7	957.5	1152.5
Sub-Total	14.2	23.8	172.9	210.8		169.9	285.8	2074.6	2530.2
C> Space Heating									
Wood Burning	334.6	4.5	31.2	370.3	0.18	1890.5	25.2	176.4	2092.1
Coal burning	12.3	46.2	6.0	64.5	0.18	69.5	261.1	33.6	364.2
Natural Gas	17.3	2.2	363.7	383.2	0.18	97.6	12.3	2054.9	2164.8
Res/Comm Oil & Others	4.6	120.0	45.7	170.3	0.18	25.7	677.9	258.3	961.9
Sub-Total	368.7	172.8	446.6	988.2		2083.3	976.5	2523.2	5583.0

(2) Major Source Inventory - Salt Lake and south Davis county

COMPANY NAME	January 1989 monthly inventory (Tons/Month) PM_{10}	SO_2	NO_x	TOTAL
AMOCO	8.9	668.9	33.7	711.5
ASPHALT MATERIALS asphalt plant	0.0	0.0	0.0	0.0
ASPHALT MATERIALS crusher	0.0	0.0	0.0	0.0
BOUNTIFUL CITY POWER	0.0	0.1	1.9	2.0
CENTRAL VALLEY WATER	0.0	0.4	17.6	18.1
CHEVRON	15.2	200.0	98.2	313.4
CPC #2 HOBUSCH 9400 SO. 1100 EAST	0.1	0.0	0.2	0.3
CPC #3 2200 NO. BOUNTIFUL	0.1	0.0	0.2	0.3
CPC WALKER WASATCH BLVD.	0.0	0.0	0.0	0.0
"CPC WHITEHILL PIT, BOUNTIFUL"	1.1	0.0	0.4	1.5
CRYSEN	0.2	0.1	10.6	11.0
FLYING J	1.9	27.6	21.1	50.6
GENEVA ROCK 350 W. 3900 SO.	0.3	0.0	0.1	0.5
GENEVA ROCK PT. OF MT.	3.4	0.0	0.0	3.4
HARPER PIT #1	0.0	0.0	0.0	0.0
HARPER PIT #10	0.0	0.0	0.0	0.0
HARSHAW FILTROL	1.5	1.0	5.0	7.5
HERCULES	26.5	0.1	20.1	46.7
INTERSTATE BRICK	4.5	0.0	0.2	4.7

(2) Major Source Inventory - Salt Lake and south Davis County (Cont'd)

COMPANY NAME	January 1989 monthly inventory (Tons/Month)			
	PM_{10}	SO_2	NO_x	TOTAL
KMC BARNEY'S	0.0	0.0	0.0	0.0
KMC BONN CRUSHER	19.9	0.0	0.0	19.9
KMC COPP CONC.	0.2	9.6	1.3	11.1
KMC MINE	275.6	52.0	337.3	664.9
KMC POWER PLANT	19.8	342.0	250.9	612.7
KMC REFINERY	0.9	0.5	3.0	4.4
KMC TALL STACK	42.9	5580.0	0.0	5622.9
KMC LOW LEVEL FUG.	69.1	1004.4	12.0	1085.5
LDS HOSPITAL	0.7	9.6	5.9	16.2
LDS WELFARE SQ.	1.0	0.2	0.2	1.3
LONE STAR	0.0	0.0	0.0	0.0
MONROC BECK ST.	5.0	0.0	0.0	5.0
MONROC COTTONWOOD	0.1	0.0	0.5	0.7
MORTON SALT	2.0	0.0	0.5	2.5
MOUNTAIN BELL	0.0	0.0	0.1	0.1
MOUNTAIN FUEL 100S 180W.	0.2	0.1	5.2	5.5
MOUNTIAN FUEL 100S. 1078 W.	0.1	0.0	2.6	2.8
MURRAY CITY POWER	0.0	0.0	0.5	0.5
OSTLER ROCKY MOUNTAIN	2.1	0.0	0.5	2.6
PARSONS KERNS	0.0	0.0	0.0	0.1
PARSONS WOODSCROSS	0.1	0.0	0.3	0.4
PHILLIPS	10.0	508.6	58.1	576.7
PIONEER SAND & GRAVEL	0.0	0.0	0.0	0.0
SALT LAKE CITY ASPHALT	0.0	0.0	0.0	0.0
SALT LAKE CO. ASPHALT	0.1	0.0	0.1	0.2
SALT LAKE VALLEY SAND & GRAVEL	0.0	0.0	0.0	0.0
SAVAGE ROCK 6200S. 3100EAST	0.0	0.0	0.2	0.2
STAKER BECK ST.	5.8	0.0	0.0	5.8
STAKER DRAPER	0.0	0.0	0.0	0.0
STAKER WEST PIT	0.0	0.0	0.0	0.0
U OF U	27.2	47.0	30.8	105.0
UNION PACIFIC RESOURCES	4.3	0.1	0.6	5.0
UP&L 40N. 100W.	0.1	0.0	2.4	2.5
UP&L GADSBY	0.0	0.0	0.0	0.0
UTAH METAL WORKS	0.6	0.0	0.0	0.7
VA HOSPITAL	0.0	0.0	0.8	0.9
W.W. & W.B. GARDNER	0.8	0.0	0.0	0.8
WOLF EXCAVATING	0.6	0.0	0.4	1.0
Sub-Total	553.2	8452.5	923.6	9929.3

(3) Totals for all catagories	PM_{10}	SO_2	NO_x	Total	Percent Breakout PM_{10}	SO_2	NO_x	Total
A> Vehicular	1100.9	219.2	1381.6	2701.7	54.0	2.5	47.2	19.5
B> Other transportation	14.2	23.8	172.9	210.8	0.7	0.3	5.9	1.5
C> Space Heating	368.7	172.8	446.6	988.2	18.1	1.9	15.3	7.1
D> Point sources	553.2	8452.5	923.6	9929.3	27.2	95.3	31.6	71.9
Grand Totals	2036.9	8868.3	2924.7	13830.0	100.0	100.0	100.0	100.0

(4) Composite automobile profile breakout:

Fuel Type	Conditions	% in profile
Leaded	Cold Start	5.5
Leaded	Hot, normal	25.3
Unleaded	Cold start	3.4
Unleaded	Hot, normal	15.6
Diesel	Cold start	9.0
Diesel	Hot, normal	41.2
Total		100.0

(5) EXPECTED REDUCTIONS IN VEHICULAR NO_x:

Mobile 4 was run in order to obtain a fleet emission factor for both the base year of 1988, and for future years as the fleet turns over with newer "low NO_x" vehicles replacing older "high NO_x" vehicles. The following is a listing of the emission fctors predicted by the model. NO_x control applied to the control strategy reflects the percentage of decrease in the emission factor relative to the base year factor of 1988. It should be noted that these emission factors reflect an average speed of 35 miles per hour.

1988	2.33 g/vmt	1994	1.623 g/vmt	2000	1.069 g/vmt
1989	2.19 g/vmt	1995	1.490 g/vmt	2001	0.990 g/vmt
1990	2.07 g/vmt	1996	1.38 g/vmt	2002	0.930 g/vmt
1991	1.93 g/vmt	1997	1.290 g/vmt	2003	0.900 g/vmt
1992	1.809 g/vmt	1998	1.205 g/vmt	2004	0.860 g/vmt
1993	1.72 g/vmt	1999	1.120 g/vmt	2005	0.854 g/vmt

Table 9.A.13 (page 3 of 6)

UTAH STATE DEPARTMENT OF HEALTH
Bureau of Air Quality
Control Strategy Worksheet

Date: 25-Jun-91

INVENTORY DATA TO DEMONSTRATE CONTROL FOR 24 HOUR STANDARD:
POST-SIP ALLOWABLE EMISSIONS

Tons Per Year (Annual)

	PM-10	SOx	NOx	TOTAL
AMOCO	113.0	2,013.0	688.0	2,814.0
ASPHALT MATERIALS asphalt plant	2.7	0.1	2.9	5.7
ASPHALT MATERIALS crusher	10.2	0.0	0.0	10.2
BOUNTIFUL CITY POWER	1.1	6.0	250.0	257.1
CENTRAL VALLEY WATER	0.7	4.0	203.7	208.3
CHEVRON	175.0	2,578.2	1,021.6	3,774.8
CPC #2 HOBUSCH 9400 SO. 1100 EAST	33.4	0.9	8.3	42.6
CPC #3 2200 NO. BOUNTIFUL	15.5	0.2	2.0	17.7
CPC WALKER WASATCH BLVD.	34.7	1.3	17.4	53.4
CPC WHITEHILL PIT ORCH DR. BOUNTIFUL	48.0	0.9	9.8	58.7
CRYSEN	2.7	206.0	156.0	364.7
FLYING J	22.0	864.6	278.7	1,165.3
GENEVA ROCK 350 W. 3900 SO.	4.5	0.5	5.3	10.3
GENEVA ROCK PT. OF MT.	81.0	9.6	21.4	112.0
HARPER PIT #1	7.8	1.9	18.4	28.1
HARPER PIT #10	16.3	1.6	17.9	35.8
HARSHAW FILTROL	34.9	31.5	94.5	160.9
HERCULES	318.1	1.5	240.9	560.5
INTERSTATE BRICK	95.9	0.0	46.5	142.4
KMC BARNEY'S	159.5	23.4	216.1	399.0
KMC BONN CONC.	234.1	0.0	0.0	234.1
KMC COPP CONC.	5.0	114.9	20.6	140.5
KMC MINE	2,801.0	78.0	4,048.1	6,927.1
KMC POWER PLANT	257.3	6,219.3	5,085.3	11,561.9
KMC REFINERY	51.9	162.6	121.0	335.5
KMC TALL STACK	876.0	14,191.2	0.0	15,067.2
KMC LOW LEVEL FUG.	464.0	4,383.8	145.0	4,992.8
LDS HOSPITAL	6.2	156.9	74.3	237.3
LDS WELFARE SQ.	11.2	0.5	1.4	13.0
LONE STAR	111.0	200.0	762.0	1,073.0
MONROC BECK ST.	69.5	8.0	17.2	94.7
* MONROC KEARNS	21.4	0.6	7.6	29.7
MORTON SALT	49.1	0.9	18.3	68.3
MOUNTAIN BELL	0.3	0.5	3.9	4.7
MOUNTAIN FUEL 100S 180W.	2.5	1.4	71.1	75.0
MOUNTIAN FUEL 100S. 1078 W.	1.1	0.4	31.2	32.7
MURRAY CITY POWER	1.6	2.4	250.0	254.0
OSTLER ROCKY MOUNTAIN	5.8	0.0	3.8	9.6
PARSONS KERNS	4.9	0.4	4.6	9.9
PARSONS WOODSCROSS	6.9	0.4	4.6	11.9
PHILLIPS	160.9	2,016.0	693.0	2,869.0
PIONEER SAND & GRAVEL	21.8	0.9	9.1	31.8
SALT LAKE CITY ASPHALT	5.3	0.1	5.7	11.1
SALT LAKE CO. ASPHALT	29.3	0.6	12.8	42.7
SALT LAKE VALLEY SAND & GRAVEL	43.9	13.9	21.4	79.2
SAVAGE ROCK 6200S. 3100EAST	28.5	1.2	14.1	43.8
STAKER BECK ST.	54.5	34.6	58.6	147.7

Table 9.A.13 (page 4 of 6)

STAKER DRAPER	13.4	1.1	16.5	31.0
STAKER WEST PIT	13.3	1.1	16.5	30.9
U OF U	74.3	219.3	245.8	539.4
UNION PACIFIC RESOURCES	28.1	1.5	15.3	44.9
UP&L 40N. 100W.	2.0	0.2	54.8	57.0
UP&L GADSBY	61.3	67.7	2,983.0	3,112.0
UTAH METAL WORKS	4.3	0.0	1.0	5.3
VA HOSPITAL	0.5	0.0	9.9	10.4
W.W. & W.B. GARDNER	24.1	6.2	13.0	43.2
WOLF EXCAVATING	3.3	0.3	3.4	7.0
TOTALS:	6,726.4	33,632.0	18,143.1	58,501.5

Table 9.A.13 (page 5 of 6)

UTAH STATE DEPARTMENT OF HEALTH
Division of Environmental Health
Bureau of Air Quality
PM10 S.I.P.
Control Strategy Worksheet

Date: 25-Jun-91

INVENTORIED EMISSIONS FROM 1988:	PM-10	SOx	NOx	TOTAL
FROM INDUSTRY:	5,619.4	95,702.1	10,967.6	112,289.1
FROM VEHICLES:	13,210.5	2,630.0	16,579.3	32,419.8
FROM SPACE HEATING:	2,083.3	976.5	2,523.2	5,583.0
FROM OTHERS:	169.9	285.8	2,074.6	2,530.2
TOTALS:	21,083.0	99,594.4	32,144.7	152,822.1

ITEMIZED PERCENTAGES OF REDUCTION:	PM-10	SOx	NOx	TOTAL
FROM INDUSTRY:	-19.70%	64.86%	-65.42%	47.90%
FROM VEHICLES:	-2.57%	41.49%	34.50%	19.96%
FROM SPACE HEATING:	47.93%	-19.56%	-19.56%	5.62%
FROM OTHERS:	0.00%	0.00%	0.00%	0.00%

PROJECTED ANNUAL EMISSIONS TOTALS:	PM-10	SOx	NOx	TOTAL
FROM INDUSTRY:	6,726.4	33,632.0	18,143.1	58,501.5
FROM VEHICLES:	13,550.0	1,538.8	10,859.4	25,948.2
FROM SPACE HEATING:	1,084.8	1,167.5	3,016.8	5,269.2
FROM OTHERS:	169.9	285.8	2,074.6	2,530.2
TOTALS:	21,531.1	36,624.1	34,093.8	92249.1

OVERALL PERCENTAGE OF REDUCTION:

EQUALS ......((INVENTORIED 1988 TOTAL) - (PROJECTED ANNUAL TOTAL)) / (INVENTORIED 1988 TOTAL)

EQUALS ..... A 39.64% REDUCTION FROM 1988 LEVELS

APPLICATION TO ANNUAL DESIGN VALUE: 56.0 ug/m^3 * (100 - 39.64) / 100 = 33.80 ug/m^3

COMPARISON WITH ANNUAL NATIONAL AMBIENT AIR QUALITY STANDARD: 33.80 ug/m^3 IS LESS THAN 50.0 ug/m^3

Table 9.A.13 (page 6 of 6)

(4) MONITORING SITE SOURCE APPORTIONMENT

NORTH SALT LAKE

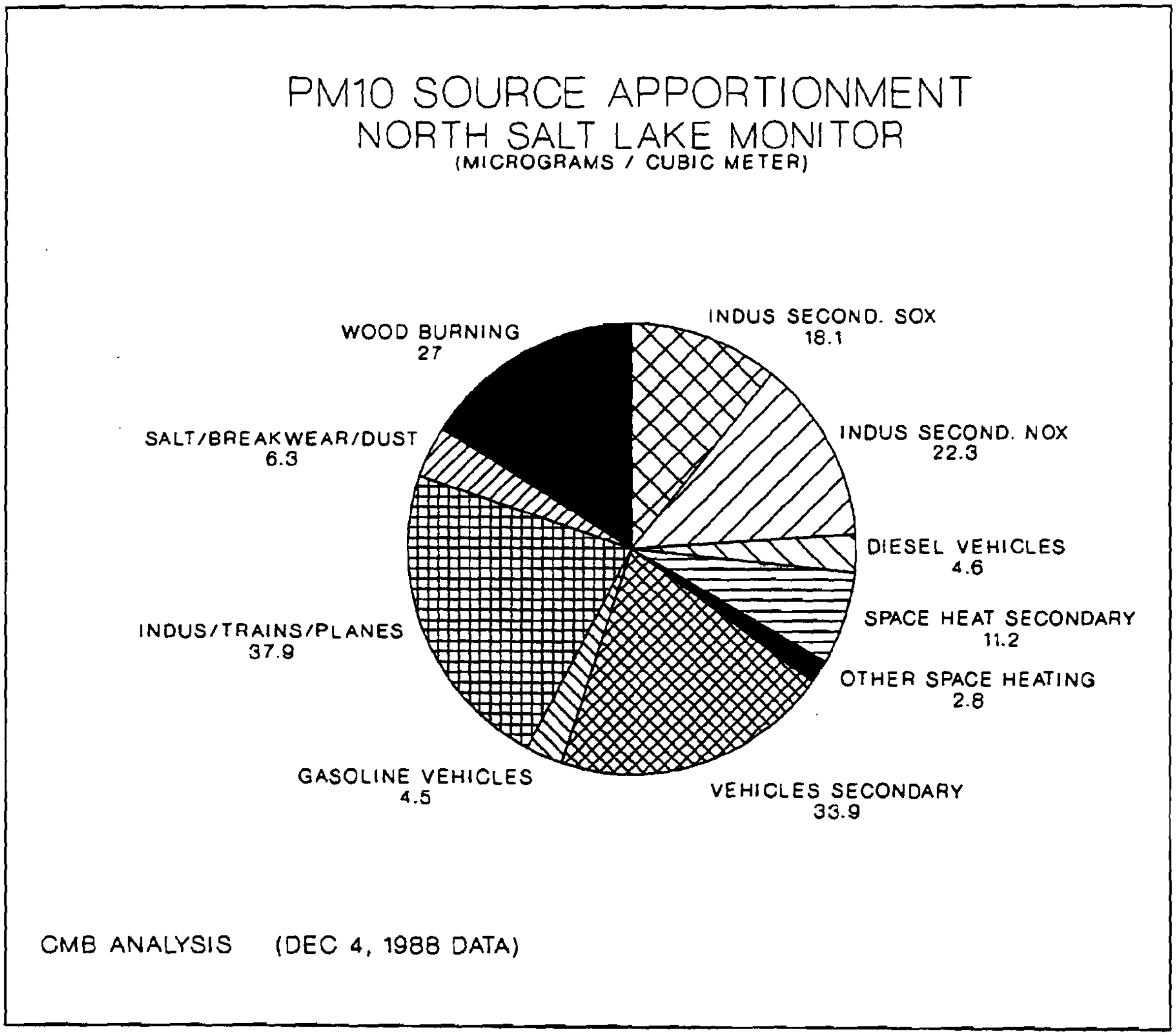

PM10 SOURCE APPORTIONMENT
NORTH SALT LAKE MONITOR
(MICROGRAMS / CUBIC METER)
WOOD BURNING
27
INDUS SECOND. SOX
18.1
SALT/BREAKWEAR/DUST
6.3
INDUS SECOND. NOX
22.3
DIESEL VEHICLES
4.6
SPACE HEAT SECONDARY
11.2
INDUS/TRAINS/PLANES
37.9
OTHER SPACE HEATING
2.8
GASOLINE VEHICLES
4.5
VEHICLES SECONDARY
33.9
CMB ANALYSIS (DEC 4, 1988 DATA)

FIGURE 9.A.19

Source Apportionment.

Figure IX.A.19 graphically demonstrates the source apportionment data contained on Table IX.A.14 on the following page and shows the contribution which the summarized components made to the overall concentration of PM_{10} at the North Salt Lake monitoring site on December 4, 1988, which is the design day for the North Salt Lake monitoring site.

Attainment Demonstration.

Tables IX.A.14, IX.A.15, and IX.A.16 show how the control strategies will reduce the PM_{10} concentrations at the North Salt Lake monitoring site to levels below the 150 $\mu g/m^3$ standard through calendar year 2003. Mobile IV projections using new motor vehicle control program NO_x emission factors indicate that there will be ample reduction from the new program to maintain ambient levels below the standard for over ten years. This is the attainment demonstration for the North Salt Lake monitoring site.

UTAH STATE DEPARTMENT OF HEALTH
Division of Environmental Health
Bureau of Air Quality
PM10 S.I.P. Control Strategy Worksheet

Site: North Salt Lake Monitor — Date: 09-Jan-91
Period: EXCEEDANCE DAYS IN WINTERS 88/89,89/90 — Projection: 2001

Source Catagory	Design Day % Contribution	Impact	Additional Control	Additional Growth	Attainment Impact
(1) Major Point sources	42.92	72.3	17.0%	0.00%	60.1
Copper smelter	4.78	8.0	41.2%	0.00%	4.7
Oil refinery cat crackers	3.28	5.5	-15.6%	0.00%	6.4
Other point sources	10.90	18.4	36.4%	0.00%	11.7
Secondary Sulfate	10.73	18.1	63.1%	0.00%	6.7
Secondary Nitrate	13.23	22.3	-37.1%	0.00%	30.6
(2) Vehicle Sub-Total	29.28	49.3			41.2
Composite Mobile sources	5.45	9.2			
Leaded Gas Fueled	1.68	2.8	6.0%	55.80%	4.1
Diesel Fueled	2.74	4.6	23.8%	55.80%	5.5
Unleaded Gas Fueled	1.04	1.7	6.0%	55.80%	2.6
Re-entrained road dust	1.26	2.1	0.6%	0.00%	2.1
Road Salting	0.00	0.0	0.0%	0.00%	0.0
Brakewear	2.49	4.2	0.0%	55.80%	6.5
Secondary Sulfate	0.28	0.5	59.0%	55.80%	0.3
Secondary Nitrate	19.80	33.4	61.3%	55.80%	20.1
(3) Space Heating Sub-Total	24.28	40.9			29.4
Wood Burning	16.03	27.0	60.0%	25.02%	13.5
Coal Burning	0.59	1.0	60.0%	25.02%	0.5
Gas & Other Heating	1.05	1.8	0.0%	25.02%	2.2
Secondary Sulfate	0.22	0.4	17.6%	25.02%	0.4
Secondary Nitrate	6.40	10.8	5.0%	25.02%	12.8
(4) Other sources	3.52	5.9			5.9
Trains	0.53	0.9	0.0%	0.0%	0.9
Planes	0.48	0.8	0.0%	0.0%	0.8
Secondary Sulfate	0.03	0.1	0.0%	0.0%	0.1
Secondary Nitrate	2.48	4.2	0.0%	0.0%	4.2
Total	100.00	168.5			136.6

Design Value 168.5 (Micrograms/Cubic Meter) 04-DEC-88

Note:
* % growth of VMT's each year = 3.0%
# % population growth per year = 1.5%
These figures were then projected out to the year2001
0.70269597 = Gadsby's capacity factor during the winter season
0.65 = KMC's Utah Power Plant capacity factor during the winter season
73.0% = expected % of diesel fuel burned that will meet new SO_2 standards
15,000 lb/hr = the worst case hourly emission rate from the tall stack

TABLE 9.A.14

DEMONSTRATION OF ATTAINMENT
NORTH SALT LAKE
PROJECTED AMBIENT PM10 CONCENTRATIONS (4-DEC-88)

Source Catagory	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
(1) Major Point sources	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1	60.1
Copper smelter	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Oil refinery cat crackers	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Other point sources	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Secondary Sulfate	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Secondary Nitrate	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
(2) Vehicle Sub-Total	44.8	44.5	43.4	42.6	42.2	41.7	41.2	41.4	40.9	40.7	41.2
Composite Mobile sources											
Leaded Gas Fueled	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1
Diesel Fueled	4.1	4.2	4.3	4.5	4.6	4.7	4.9	5.0	5.2	5.3	5.5
Unleaded Gas Fueled	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5	2.6
Re-entrained road dust	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Road Salting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brakewear	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3	6.5
Secondary Sulfate	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Secondary Nitrate	28.6	27.8	26.3	25.1	24.1	23.2	22.2	21.8	20.8	20.2	20.1
(3) Space Heating Sub-T	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5	29.0	29.4
Wood Burning	11.6	11.8	12.0	12.2	12.4	12.5	12.7	12.9	13.1	13.3	13.5
Coal Burning	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Gas & Other Heating	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.2	2.2
Secondary Sulfate	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Secondary Nitrate	11.0	11.2	11.4	11.5	11.7	11.9	12.1	12.2	12.4	12.6	12.8
(4) Other sources	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Trains	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Planes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Secondary Sulfate	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Secondary Nitrate	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Total	136.1	136.1	135.4	135.1	135.0	134.9	134.9	135.4	135.3	135.6	136.6

TABLE 9.A.15

NORTH SALT LAKE

The following table shows the attainment value (after applying the control strategy) for each day that CMB modeling was performed. These values are shown for the attainment demonstration in 1993, and for each year thereafter through 2001.

CMB DAY: YEAR	26-Jan-88	05-Feb-88	06-Feb-88	08-Feb-88	02-Dec-88	03-Dec-88	04-Dec-88	18-Jan-89	27-Jan-89	30-Jan-89	17-Feb-89	05-Dec-89
1993	128.4	106.7	82.6	123.3	120.8	149.9	136.1	133.6	118.3	131.1	137.0	108.5
1994	128.7	106.9	82.9	123.6	121.1	150.0	136.2	134.1	118.4	131.5	137.1	109.0
1995	128.3	106.7	83.0	123.3	121.0	149.3	135.5	134.0	117.8	131.3	136.6	109.5
1996	128.3	106.6	83.2	123.3	121.1	149.1	135.1	134.2	117.6	131.4	136.3	110.0
1997	128.4	106.7	83.5	123.4	121.4	149.1	135.0	134.6	117.5	131.7	136.4	110.6
1998	128.6	106.9	83.8	123.7	121.7	149.1	135.0	135.1	117.6	132.0	136.4	111.2
1999	128.8	107.0	84.1	123.8	121.9	149.1	134.9	135.5	117.5	132.3	136.5	111.8
2000	129.4	107.5	84.7	124.5	122.6	149.8	135.4	136.3	118.1	133.1	137.1	112.6
2001	129.6	107.6	85.0	124.7	122.9	149.8	135.4	136.8	118.1	133.4	137.1	113.2

TABLE 9.A.16

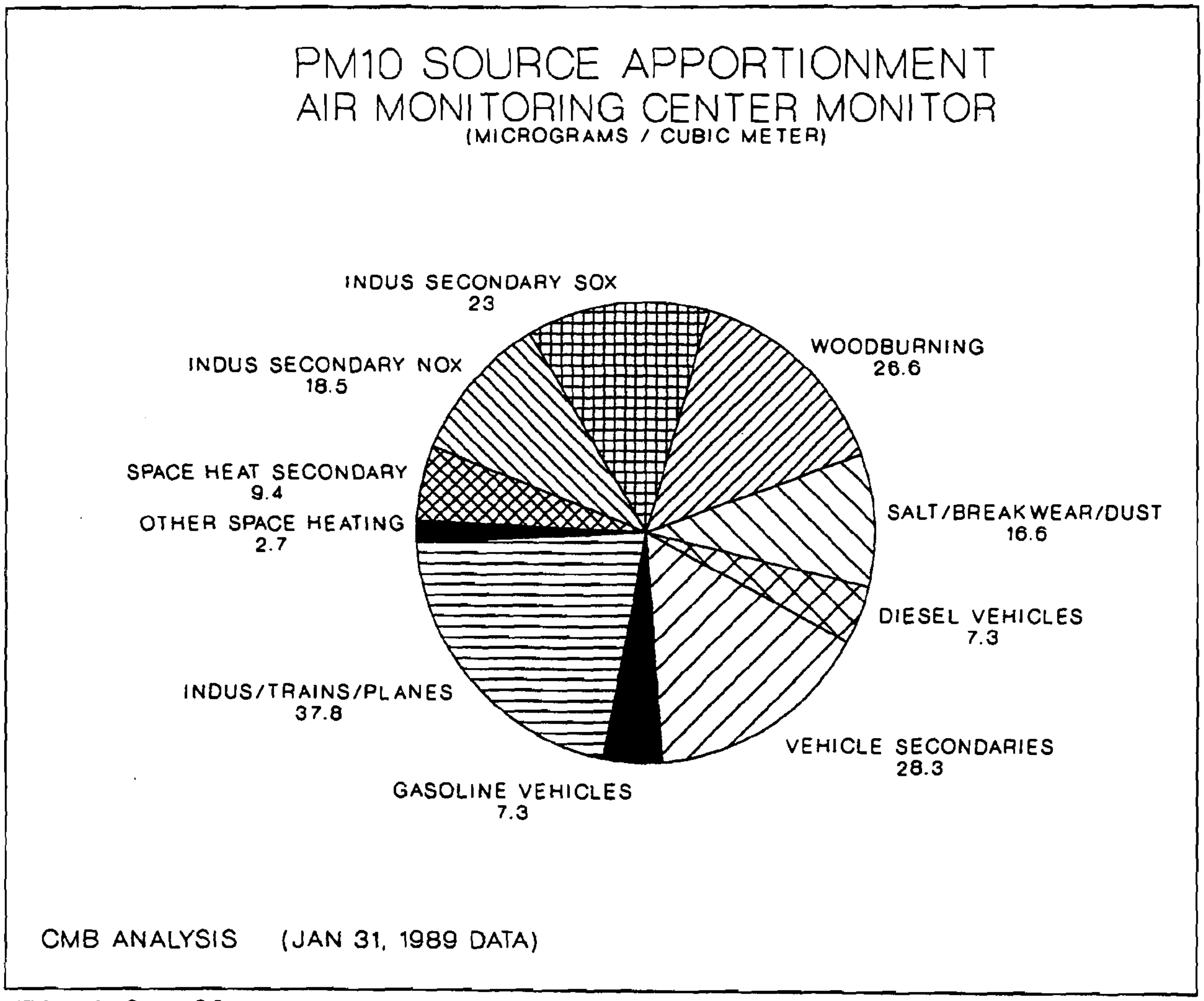

PM10 SOURCE APPORTIONMENT
AIR MONITORING CENTER MONITOR
(MICROGRAMS / CUBIC METER)
INDUS SECONDARY SOX
23
WOODBURNING
26.6
INDUS SECONDARY NOX
18.5
SPACE HEAT SECONDARY
9.4
OTHER SPACE HEATING
2.7
SALT/BREAKWEAR/DUST
16.6
DIESEL VEHICLES
7.3
INDUS/TRAINS/PLANES
37.8
VEHICLE SECONDARIES
28.3
GASOLINE VEHICLES
7.3
CMB ANALYSIS (JAN 31, 1989 DATA)

FIGURE 9.A.20

Source Apportionment.

Figure IX.A.19 graphically demonstrates the source apportionment data contained on Table IX.A.14 on the following page and shows the contribution which the summarized components made to the overall concentration of PM_{10} at the North Salt Lake monitoring site on December 4, 1988, which is the design day for the North Salt Lake monitoring site.

Attainment Demonstration.

Tables IX.A.14, IX.A.15, and IX.A.16 show how the control strategies will reduce the PM_{10} concentrations at the North Salt Lake monitoring site to levels below the 150 $\mu g/m^3$ standard through calendar year 2003. Mobile IV projections using new motor vehicle control program NO_x emission factors indicate that there will be ample reduction from the new program to maintain ambient levels below the standard for over ten years. This is the attainment demonstration for the North Salt Lake monitoring site.

UTAH STATE DEPARTMENT OF HEALTH
Division of Environmental Health
Bureau of Air Quality
PM10 S.I.P Control Strategy Worksheet

Site: Air monitoring Center — Date: 09-Jan-91
Period: EXCEEDANCE DAYS IN WINTERS 88/89,89/90 — Projection: 2000

Source Catagory	Design Day % Contribution	Impact	Additional Control	Additional Growth	Attainment Impact
(1) Major Point sources	41.17	73.0	19.4%	0.00%	58.8
Copper smelter	0.00	0.0	41.2%	0.00%	0.0
Oil refinery cat crackers	5.35	9.5	-15.8%	0.00%	11.0
Other point sources	12.42	22.0	36.4%	0.00%	14.0
Secondary Sulfate	12.97	23.0	63.1%	0.00%	8.5
Secondary Nitrate	10.42	18.5	-37.1%	0.00%	25.4
(2) Vehicle Sub-Total	33.47	59.4			54.0
Composite Mobile sources	8.18	14.5			
Leaded Gas Fueled	2.52	4.5	6.0%	42.58%	6.0
Diesel Fueled	4.10	7.3	23.8%	42.58%	7.9
Unleaded Gas Fueled	1.55	2.8	6.0%	42.58%	3.7
Re-entrained road dust	7.54	13.4	0.6%	0.00%	13.3
Road Salting	0.00	0.0	0.0%	0.00%	0.0
Brakewear	1.82	3.2	0.0%	42.58%	4.6
Secondary Sulfate	0.34	0.6	59.0%	42.58%	0.3
Secondary Nitrate	15.59	27.7	54.1%	42.58%	18.1
(3) Space Heating Sub-Total	21.86	38.8			26.5
Wood Burning	15.02	26.6	60.0%	19.56%	12.7
Coal Burning	0.55	1.0	60.0%	19.56%	0.5
Gas & Other Heating	0.98	1.7	0.0%	19.56%	2.1
Secondary Sulfate	0.27	0.5	0.0%	19.56%	0.6
Secondary Nitrate	5.04	8.9	0.0%	19.56%	10.7
(4) Other sources	3.51	6.2			6.2
Trains	0.79	1.4	0.0%	0.0%	1.4
Planes	0.73	1.3	0.0%	0.0%	1.3
Secondary Sulfate	0.04	0.1	0.0%	0.0%	0.1
Secondary Nitrate	1.95	3.5	0.0%	0.0%	3.5
Total	100.00	177.4			145.5

Design Value 177.4 (Micrograms/Cubic Meter) on 31-Jan-89
These figures were projected out to the year: 2000

Note:
* % growth of VMT's each year = 3.0%
# % population growth per year = 1.5%

0.70269597 = Gadsby's capacity factor during the winter season
0.65 = KMC's Utah Power Plant capacity during the winter season
73.0% = expected % of diesel fuel burned that will meet new SO_2 standards
15,000 lb/hr = the worst case hourly emission rate from the tall stack

TABLE 9.A.17

DEMONSTRATION OF ATTAINMENT
AIR MONITORING CENTER
PROJECTED AMBIENT PM_{10} CONCENTRATIONS (31-JAN-89)

Source Catagory	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
(1) Major Point sources	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
Copper smelter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil refinery catcracker	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Other point sources	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Secondary Sulfate	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Secondary Nitrate	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
(2) Vehicle Sub-Total	55.3	55.2	54.5	54.1	53.9	53.8	53.6	54.0	53.8	54.0	54.6
Composite Mobile sources											
Leaded Gas Fueled	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.4	6.5
Diesel Fueled	6.4	6.6	6.8	7.0	7.2	7.5	7.7	7.9	8.2	8.4	8.6
Unleaded Gas Fueled	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0
Re-entrained road dust	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
Road Salting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brakewear	3.8	3.9	4.0	4.1	4.2	4.3	4.5	4.6	4.8	4.9	5.0
Secondary Sulfate	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Secondary Nitrate	23.7	23.0	21.8	20.8	20.0	19.2	18.4	18.1	17.3	16.7	16.7
(3) Space Heating Sub-T	23.9	24.3	24.6	25.0	25.4	25.8	26.2	26.5	26.9	27.3	27.8
Wood Burning	11.5	11.7	11.8	12.0	12.2	12.4	12.6	12.7	12.9	13.1	13.3
Coal Burning	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Gas & Other Heating	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.2
Secondary Sulfate	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Secondary Nitrate	9.6	9.8	9.9	10.1	10.2	10.4	10.5	10.7	10.9	11.0	11.2
(4) Other sources	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Trains	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Planes	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Secondary Sulfate	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Secondary Nitrate	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Total	144.2	144.5	144.2	144.2	144.3	144.6	144.8	145.5	145.8	146.3	147.4

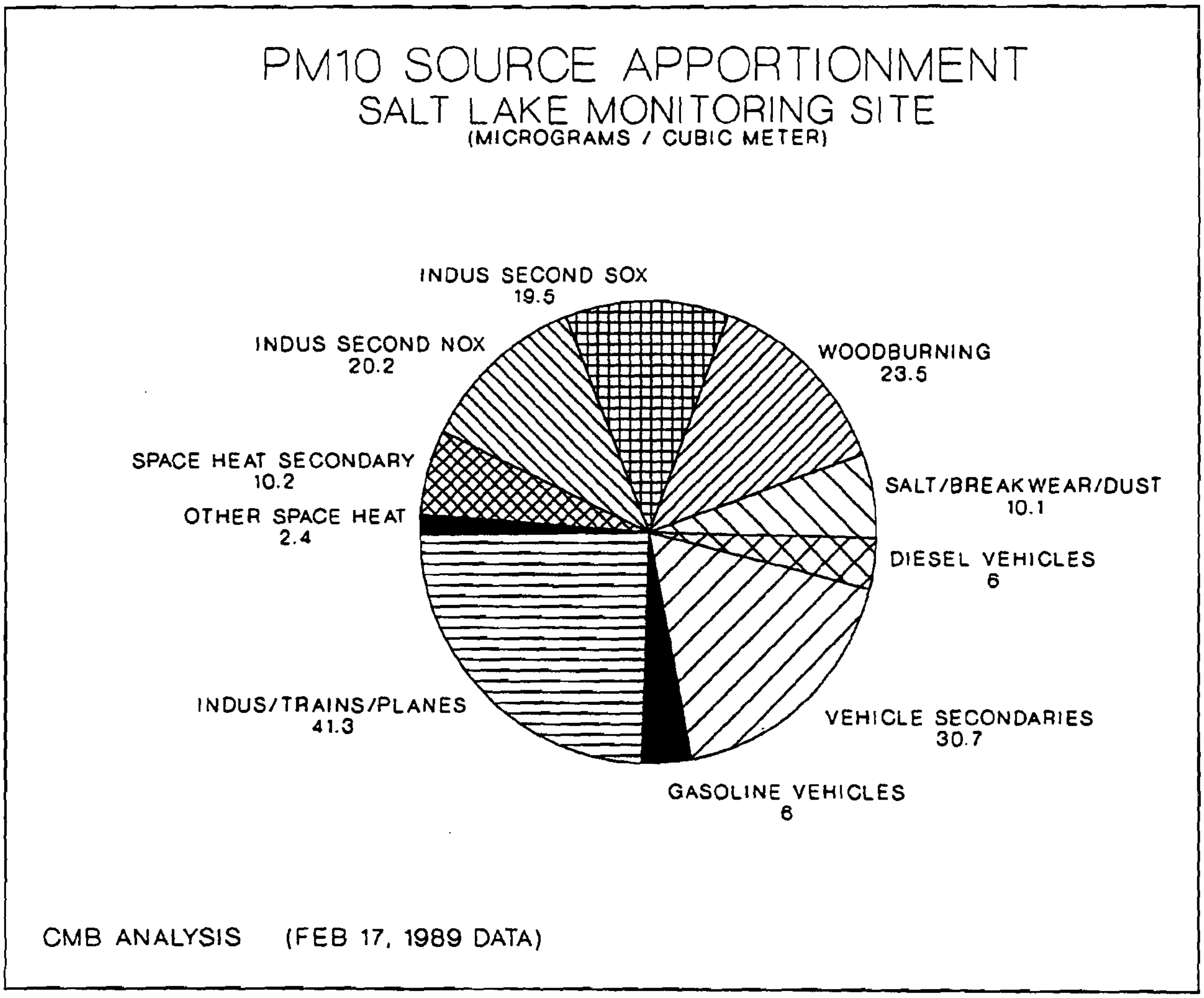
TABLE 9.A.18

AIR MONITORING CENTER

The following table shows the attainment value (after applying the control strategy) for each day that CMB modeling was performed. These values are shown for the attainment demonstration in 1993, and for each year thereafter through 2000.

CMB DAY: / YEAR	1-18-89	1-19-89	1-20-89	1-30-89	1-31-89	2-17-89	2-18-89	11-21-89	12-02-89	12-03-89	12-04-89	12-06-89	12-27-89
1993	148.8	133.2	121.0	134.9	144.3	139.3	120.6	93.9	96.2	100.0	110.1	92.6	106.2
1994	149.0	133.6	121.4	135.1	144.6	139.6	120.7	94.3	96.4	100.1	110.5	93.2	106.4
1995	148.5	133.4	121.3	134.5	144.2	139.2	120.2	94.5	96.3	99.9	110.7	93.8	106.2
1996	148.4	133.5	121.4	134.4	144.2	139.1	120.0	94.8	96.4	99.9	111.0	94.4	106.2
1997	148.6	133.8	121.7	134.4	144.4	139.2	120.0	95.2	96.5	100.0	111.4	95.0	106.3
1998	148.8	134.1	122.1	134.6	144.6	139.4	120.0	95.6	96.7	100.1	111.8	95.7	106.5
1999	149.0	134.5	122.4	134.7	144.8	139.5	120.0	96.0	96.9	100.3	112.2	96.4	106.6
2000	149.8	135.3	123.3	135.4	145.6	140.2	120.7	96.5	97.4	100.7	112.8	97.2	107.0

TABLE 9.A.19


PM10 SOURCE APPORTIONMENT
SALT LAKE MONITORING SITE
(MICROGRAMS / CUBIC METER)
INDUS SECOND SOX
19.5
WOODBURNING
23.5
INDUS SECOND NOX
20.2
SPACE HEAT SECONDARY
10.2
SALT/BREAKWEAR/DUST
10.1
OTHER SPACE HEAT
2.4
DIESEL VEHICLES
6
INDUS/TRAINS/PLANES
41.3
VEHICLE SECONDARIES
30.7
GASOLINE VEHICLES
6
CMB ANALYSIS (FEB 17, 1989 DATA)
FIGURE 9.A.21

Source Apportionment.

Figure IX.A.21 graphically demonstrates the source apportionment data contained on Table IX.A.20 on the following page and shows the contribution which the summarized components made to the overall concentration of PM_{10} at the Salt Lake monitoring site on February 17, 1989, which is the design day for the Salt Lake monitoring site.

Attainment Demonstration.

Tables IX.A.20, IX.A.21, and IX.A.22 show how the control strategies will reduce the PM_{10} concentrations at the Salt Lake monitoring site to levels below the 150 $\mu g/m^3$ standard through calendar year 2003. Mobile IV projections using new motor vehicle control program NO_x emission factors indicate that there will be ample reduction from the new program to maintain ambient levels below the standard for over ten years. This is the attainment demonstration for the Salt Lake monitoring site.

UTAH STATE DEPARTMENT OF HEALTH
Division of Environmental Health
Bureau of Air Quality
PM10 S.I.P. Control Strategy Worksheet

Site: Salt Lake City Monitor — Date: 09-Jan-91
Period: EXCEEDANCE DAYS IN WINTERS 88/89,89/90 — Projection:2003

Source Catagory	Design Day % Contribution	Impact	Additional Control	Additional Growth	Attainment Impact
(1) Major Point sources	43.98	74.7	20.3%	0.00%	59.6
Copper smelter	5.69	9.7	41.2%	0.00%	5.7
Oil refinery cat crackers	3.23	5.5	-15.6%	0.00%	6.3
Other point sources	11.71	19.9	36.4%	0.00%	12.6
Secondary Sulfate	11.45	19.5	63.1%	0.00%	7.2
Secondary Nitrate	11.90	20.2	-37.1%	0.00%	27.7
(2) Vehicle Sub-Total	31.19	53.0			46.4
Composite Mobile sources	7.09	12.0			
Leaded Gas Fueled	2.18	3.7	6.0%	55.80%	5.4
Diesel Fueled	3.56	6.0	23.8%	55.80%	7.2
Unleaded Gas Fueled	1.35	2.3	6.0%	55.80%	3.4
Re-entrained road dust	4.21	7.1	0.6%	0.00%	7.1
Road Salting	0.00	0.0	0.0%	0.00%	0.0
Brakewear	1.80	3.0	0.0%	55.80%	4.8
Secondary Sulfate	0.30	0.5	59.0%	55.80%	0.3
Secondary Nitrate	17.80	30.2	61.3%	55.80%	18.2
(3) Space Heating Sub-Total	21.25	36.1			26.1
Wood Burning	13.85	23.5	60.0%	25.02%	11.8
Coal Burning	0.51	0.9	60.0%	25.02%	0.4
Gas & Other Heating	0.90	1.5	0.0%	25.02%	1.9
Secondary Sulfate	0.23	0.4	17.6%	25.02%	0.4
Secondary Nitrate	5.75	9.8	5.0%	25.02%	11.6
(4) Other sources	3.58	6.1			6.1
Trains	0.69	1.2	0.0%	0.0%	1.2
Planes	0.63	1.1	0.0%	0.0%	1.1
Secondary Sulfate	0.03	0.1	0.0%	0.0%	0.1
Secondary Nitrate	2.23	3.8	0.0%	0.0%	3.8
Total	100.00	169.9			138.1

Design Value = 169.9 (Micrograms/Cubic Meter) on 17-Feb-89
Note:
* % growth of VMT's each year = 3.0%
# % population growth per year = 1.5%
These figures were then projected out to the year: 2003
0.70269597 = Gadsby's capacity factor during the winter season
0.65 = KMC's Utah Power Plant capacity factor during the winter season
73.0% = expected % of diesel fuel burned that will meet new SO_2 standards
15,000 lb/hr = the worst case hourly emission rate from the tall stack

TABLE 9.A.20

DEMONSTRATION OF ATTAINMENT
SALT LAKE CITY
PROJECTED AMBIENT PM_{10} CONCENTRATIONS (17-FEB-89)

Source Catagory	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
(1) Major Point sources	59.6	59.6	59.6	59.6	59.6	59.6	59.6	59.6	59.6	59.6	59.6
Copper smelter	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Oil refinery cat crackers	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Other point sources	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Secondary Sulfate	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Secondary Nitrate	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7
(2) Vehicle Sub-Total	48.6	48.4	47.5	47.0	46.6	46.3	46.0	46.2	45.8	45.8	46.4
Composite Mobile sources											
Leaded Gas Fueled	4.0	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.1	5.3	5.4
Diesel Fueled	5.3	5.5	5.7	5.8	6.0	6.2	6.4	6.6	6.8	7.0	7.2
Unleaded Gas Fueled	2.5	2.6	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4
Re-entrained road dust	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Road Salting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brakewear	3.5	3.6	3.8	3.9	4.0	4.1	4.2	4.3	4.5	4.6	4.8
Secondary Sulfate	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Secondary Nitrate	25.9	25.2	23.8	22.7	21.9	21.0	20.1	19.8	18.9	18.3	18.2
(3) Space Heating Sub-Total	22.5	22.9	23.2	23.6	23.9	24.3	24.6	25.0	25.4	25.8	26.1
Wood Burning	10.1	10.3	10.4	10.6	10.8	10.9	11.1	11.3	11.4	11.6	11.8
Coal Burning	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Gas & Other Heating	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9
Secondary Sulfate	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Secondary Nitrate	10.0	10.2	10.3	10.5	10.6	10.8	10.9	11.1	11.3	11.4	11.6
(4) Other sources	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Trains	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Planes	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Secondary Sulfate	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Secondary Nitrate	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Total	136.8	136.9	136.3	136.1	136.1	136.2	136.2	136.8	136.8	137.2	138.1

Table 9.A.21

DEMONSTRATION OF MAINTENANCE
SALT LAKE CITY

The following table shows the attainment value (after applying the control strategy) for each day for which CMB modeling was performed. These values are shown for the attainment demonstration in 1993, and for each year thereafter through 2003.

CMB DAY: YEAR	04-Jan-88	26-Jan-88	28-Jan-88	05-Feb-88	03-Dec-88	18-Jan-89	20-Jan-89	30-Jan-89	17-Feb-89
1993	89.5	120.5	83.3	107.6	126.3	138.6	112.2	116.2	136.8
1994	89.8	120.8	83.6	107.7	126.4	138.9	112.7	116.5	136.9
1995	89.8	120.7	83.9	107.4	125.9	138.6	112.9	116.3	136.4
1996	89.9	120.7	84.2	107.3	125.6	138.6	113.3	116.4	136.2
1997	90.2	121.0	84.6	107.4	125.6	138.7	113.8	116.6	136.2
1998	90.5	122.2	85.0	107.5	125.6	139.0	114.4	116.9	136.2
1999	90.7	121.5	85.4	107.6	125.6	139.2	114.9	117.1	136.2
2000	91.2	122.1	86.0	108.1	126.1	139.9	115.7	117.8	136.8
2001	91.5	122.4	86.4	108.2	126.1	140.2	116.3	118.1	136.9
2002	92.0	122.9	86.9	108.5	126.4	140.7	117.0	118.6	137.2
2003	92.7	123.8	87.6	109.3	127.3	141.8	118.0	119.5	138.2

Table 9.A.22

SECTION IX.A.6 CONTROL STRATEGIES

(1) The following control strategies were implemented to control PM_{10} emissions in the Magna portion of the Salt Lake nonattainment area:

After the issuance of a Notice of Violation and a series of negotiations between Kennecott and the Utah Air Conservation Committee, an agreement was signed whereby Kennecott agreed to:

(a) construct a series of dikes and sprinkler systems on the tailings pond which would allow the company to distribute water on the pond until the company began operation;

(b) replace the existing tailings distribution system to guarantee that the tailings pond would remain covered with wet tailings after the company began operation;

(c) apply controls to the periphery of the pond;

(d) develop and submit a plan to control emissions from the pond in the event of a temporary plant shutdown; and

(e) develop a plan to control emissions from the pond in the event of a permanent plant shutdown.

Following the restart of operations by Kennecott, the Executive Secretary of the Air Conservation Committee issued a compliance order dated October 4, 1989, to Kennecott which required Kennecott to replace and upgrade the peripheral discharge system for tailings flowing to the tailings pond and implement plans for dust control during current operation, temporary shutdown, and permanent shutdown of the mine and associated tailings pond. The peripheral discharge system completed July 1, 1988, allows Kennecott to keep the surface of the tailings pond wet and thereby reduce or eliminate blowing tailings. As summarized in Table IX.A.23, since the completion of the new system, similar meteorological conditions have not resulted in a violation of the NAAQS. The compliance order has corrected the problem of ambient PM_{10} violations caused by blowing Kennecott tailings in the Magna area.

DATE	MEASURED CONCEN-TRATION	MAXIMUM WIND SPEED (MPH)	WIND DIRECTION (DEGREES)
9-27-88	87	9	232
5-18-89	35	25	156
5-23-89	42	19	231
8-23-89	53	23	169
9-30-89	36	25	293

TABLE IX.A.23

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IX.A.6.b. The following industrial control strategies will be implemented to control PM10 emissions in the Utah County nonattainment Area:

a) All industrial sources of PM10 in Utah County comprise 63.5% of the PM10 impact at the Lindon monitoring site, 68.2% at the West Orem monitoring site, and 50.5% at the North Provo monitoring site. New operating parameters and emissions limitations for PM10, SO2, and NOx for the most significant existing stationary sources of primary and secondary PM10 impacting the ambient concentrations at the monitor site are detailed in Section IX, Part H of the Utah State Implementation Plan.

Table IX.A.24.a lists the annual emissions caps for the significant sources (i.e., those whose emissions exceed 100 tons/year of primary PM10, 200 tons/year of NOx or 250 tons/year of SO2) except for Geneva Steel.

Summary of Tons/Year Emission Caps			
Company	Primary PM_{10}	NO_x	SO_2
Geneva Nitrogen, Inc.	86.	223.8	
Provo City Power		254	
Springville City Power		248	

TABLE IX.A.24.a

Due to shutting down or reducing operations at the coke plant, sinter plant, foundry and rolling mill scarfer facility, and fuel switching, Geneva Steel is in the process of banking a significant amount of their emissions. Table IX.A.24.b lists the allowable annual emissions limits at Geneva Steel before the emissions mentioned above are banked, Table IX.A.24.c lists the banked emissions from Geneva Steel used in the attainment demonstration for this revision of the PM10 SIP, and Table IX.A.24.d lists the annual emissions limits at Geneva after those emissions are banked (i.e., subtracting Table IX.A.24.c from Table IX.A.24.b results in Table IX.A.24.d).

Annual Emissions - Geneva Steel (Before Banking) - Tons/Year			
Geneva Steel Process	**PM_{10}**	**SO_2**	**NO_x**
Coke Plant	491.4	454.9	
Sinter Plant	101.0		
Blast Furnace	454.4		
Q-BOP	205.4		
Geneva Other	499.1		
Secondary Sulfate		994.4	
Secondary Nitrate			4234.2

TABLE IX.A.24.b

Banked Emissions - Geneva Steel (Tons/Year)			
Geneva Steel Process	**PM_{10}**	**SO_2**	**NO_x**
Coke Plant	461.8	454.9	557.2
Sinter Plant	101.0	434.2	705.2
Q-BOP	27.2		
Geneva Other	51.0		
Totals	641	889.1	1262.4

TABLE IX.A.24.c

Annual Emissions - Geneva Steel (After Banking) - Tons/Year			
Geneva Steel Process	**PM_{10}**	**SO_2**	**NO_x**
Coke Plant	29.6	0.0	(see footnote 1)
Sinter Plant	(see footnote 2)	(see footnote 2)	(see footnote 2)
Blast Furnace	454.4		
Q-BOP	178.2		
Geneva Other	448.1		
Secondary Sulfate		560.2	
Secondary Nitrate			2971.8

TABLE IX.A.24.d

Table IX.A.25.a lists the 24-hr emission limits for the significant sources (i.e., those whose emissions exceed 100 tons/year of primary PM10, 200 tons/year of NOx, or 250 tons/year of SO2) except Geneva Steel.

Summary of Tons/Day Emission Limits			
Company	**Primary PM_{10}**	**NO_x**	**SO_2**
Geneva Nitrogen, Inc.	0.24	0.622	
Provo City Power		2.45	
Springville City Power		1.68	
Geneva Rock Products Asphalt Plant Baghouse Stack	0.103	0.568	0.484

TABLE IX.A.25.a

Table IX.A.25.b lists the allowable daily emissions at Geneva Steel for September through May after the banking mentioned above and Table IX.A.25.c lists the allowable daily emissions at Geneva Steel for June through August after the banking mentioned above.

Daily Emissions - Geneva Steel (September - May) - Tons/Day			
Geneva Steel Process	**PM_{10}**	**SO_2**	**NO_x**
Coke Plant	0.1	0.0	(see footnote 1)
Sinter Plant	(see footnote 2)	(see footnote 2)	(see footnote 2)
Blast Furnace	1.3		
Q-BOP	0.5		
Geneva Other	1.2		
Secondary Sulfate		1.0	
Secondary Nitrate			7.7

TABLE IX.A.25.b

Daily Emissions - Geneva Steel (June - August) - Tons/Day			
Geneva Steel Process	**PM_{10}**	**SO_2**	**NO_x**
Coke Plant	0.1	0.0	(see footnote 1)
Sinter Plant	(see footnote 2)	(see footnote 2)	(see footnote 2)
Blast Furnace	1.3		
Q-BOP	0.5		
Geneva Other	1.4		
Secondary Sulfate		3.4	
Secondary Nitrate			9.6

TABLE IX.A.25.c

Footnote 1: All NOx emissions from coke plant ovens have been banked. Emissions of NOx associated with continuing operations in the vicinity of the coke plant (coke pile handling) are accounted for in the secondary nitrate item.

Footnote 2: All emissions of PM10, SO2, and NOx from the sinter plant have been banked.

The methods used to establish both the 24-hour emission limits and annual caps are documented in Supplement II-02 of the Technical Support Document and relevant permits.

In Tables IX.A.24.b, c, and d and Tables IX.A.25.b and c, the "Geneva Other" category includes the power house, rolling mill, and fugitives. In Tables IX.A.25.b and c, the "Secondary Sulfate" category includes SO2 emissions from the sinter plant, blast furnace, Q-BOP, and sources included in the "Geneva Other" category and the "Secondary Nitrate" category includes NOx emissions from the coke plant, sinter plant, blast furnace, Q-BOP, and sources included in the "Geneva Other" category.

Notwithstanding any other provision in the Utah SIP, no change to this SIP revision shall be effective to change the federal enforceability of the emission limits or other requirements of the Utah County PM10 SIP revision without EPA approval of such change as a SIP revision.

(3) The following industrial control strategies will be implemented to control PM_{10} emissions in the Salt Lake nonattainment area:

a) All industrial sources of PM_{10} located in or impacting the Salt Lake nonattainment area comprised 41.17% of the PM_{10} impact (primary and secondary) at the AMC monitoring site, 43.98% at the Salt Lake monitoring site, and 42.92% at the North Salt Lake monitoring site on the design day at each site which occurred during the winter period. RACT requirements were developed for all sources impacting the nonattainment area, as a minimum, and new operating parameters and emissions limitations for PM_{10}, SO_2, and NO_x for all existing sources of primary and secondary PM_{10} impacting the ambient concentrations at the monitor sites are detailed in Appendix A of this Section IX of the SIP. It must be noted that, although the allowable emissions levels have been reduced significantly, the actual emissions levels have the potential to increase slightly, since some sources in the inventory were not operating or in existence during the winter of 1988/89, and the State is required to demonstrate attainment when all sources are operating at their permitted levels. This is documented in the Technical Support Document.

(b) Refinery Category. The refineries located in Salt Lake and Davis counties had emission limitations and annual emission estimates assigned in the PM_{10} SIP based on the following rationale:

(i) After reviewing several years worth of operational records provided by the five refineries for emission estimates/calculations and production levels, the State agreed with the refinery officials that there was significant variability from day to day and from year to year. Therefore, the refineries were allowed maximum never-to-be exceeded daily limits of PM_{10}, SO_2, NO_x based on the apparent variability. Emissions were capped at these maximum levels from the sources that could have their emissions determined by fuel metering/and calculations and from the other sources that would be stack tested every 1-3 years. The process flaring emissions and the emissions from the sulfur removal unit turnarounds were not included in the emission limitations.

(ii) The basic RACT applied to all refineries was: 1) a sulfur removal unit/plant (SRU) that will remove 95% of the sulfur from the streams fed to it (Amine plant and sour water overhead stripper streams included), and for which routine maintenance turnarounds are restricted to the summer months; 2) a restriction on the burning of liquid fuel oil except during natural gas curtailments and/or as specified in the individual subsection of Appendix A wherein a refinery could choose to burn this fuel but would need to trade-off the emissions equally (ton of SO_2 for ton of NO_x); and 3) a requirement for the use of Low-SO_x catalyst emission reduction techniques/procedures for fluid catalytic cracking units which would result in no more than 9.8 kg of SO_2 emitted per 1000 kg of coke burn-off (9.8 lb SO_2/1000 lb coke burn-off). Because the increase of sulfur content of the crude feed-stock now being experienced and expected to continue for the refineries, the State felt it was necessary to allow some flexibility by not requiring RACT controls/reductions on the NO_x sources. Thus, as the sulfur content in the crude increased, the refineries would be allowed to increase their SO_2 emissions by trading-off NO_x reductions from application of Lo-NO_x technologies, as approved by the Executive Secretary.

(iii) Low-SO_x catalyst technology was considered RACT; however, a refinery could choose to trade-off NO_x emissions equivalent to that obtained by the 9.8 lb SO_2/1000 lb coke burn-off NSPS limit. Chevron USA choose to do this.

(iv) No burning of liquid fuel oil was considered RACT, if it could be justified economically; however, a refinery could choose to trade-off the SO_2 by an increase of SRU efficiency or by applying NO_x controls. AMOCO may choose to do this.

(v) An allowance was made for AMOCO, Flying-J and Crysen because of their low process flaring emissions in comparison to those from Chevron and Phillips. Chevron's estimated flaring emissions (approx 250 tpy SO_2) were used as a basis and an amount was allowed for the three refineries as calculated using a feed through put ratio:

eg: AMOCO throughput (bbl/day) x Chevron flare SO_2 emissions = allowance of SO_2 for AMOCO
Chevron throughput (bbl/day)

These ratioed amounts were then added to the three refinery SO_2 allowed emissions used for compliance.

(vi) An allowance was made for Flying-J and Crysen using low sulfur content crude in their operation in comparison with AMOCO, Chevron and Phillips' average crude sulfur contents. Flying-J and Crysen were allowed to use AMOCO's estimated 1988 0.24% by weight sulfur content crude in the calculations of Post-SIP emissions for these two refineries.

(4) Solid Fuel Burning Devices:

Solid Fuel Burning Devices contribute a significant proportion to the PM_{10} concentrations in Davis, Salt Lake, and Utah Counties.

In 1987 the UACC adopted Subsection 4.13, UACR, Emissions Standards for Residential Solid Fuel Burners and Fireplaces, which established a limitation on the sulfur and volatile ash content of coal sold for direct space heating for residential solid fuel burners and fireplaces, and limited the emissions from these devices to 40% opacity as measured by EPA Method 9. As part of the development process of this SIP, the maximum opacity was changed to 20%. Although no credit will be claimed for these control strategies, its enforcement can help insure the proper operation of solid fuel burning devices.

The Bureau of Air Quality is proposing the initiation of a program beginning September 1, 1992, to control emissions from residential solid fuel burning devices which is detailed below. The BAQ will collect the data necessary to verify the effectivness of the program, and begin its information, public awareness, and public education programs before the program takes effect in 1992. The period from the promulgation of the program until the winter of 1992/1993 will also allow the BAQ the opportunity to implement and verify the proper functioning of the notification system that will be established and examine the potential of using a voluntary no-burn period to achieve the reductions in woodburning emissions required to meet the goals of this SIP. This interim period will also allow citizens who will be affected by the mandatory no-burn periods time to adjust their home heating requirements. Also, residents with sole source devices will be requested to certify these as such with the Executive Secretary or the appropriate local district health office.

(a) Emissions from wood burning devices account for 37.7 $\mu g/m^3$, which is equivalent to 14.3% of the PM_{10} concentrations at West Orem in Utah County. The following control strategies will be used to reduce emissions from wood burning devices in Utah County:

(i) Paragraph 4.13.3, UACR establishes mandatory no burn periods (beginning September 1, 1992) for areas in Utah County which are north of the southernmost border of Payson City and east of State Route 68. The regulation establishes a mandatory no burn period when the ambient concentration of PM_{10} reaches 120 $\mu g/m^3$ as measured by the real-time monitor located at the Lindon monitoring site. During the mandatory no-burn period, citizens may not use any solid fuel burning devices or fireplaces except those which are registered with the Bureau of Air Quality or the local health district office as being the sole source of heat for the entire residence or which have no visible emissions. The no-burn period will be in effect until the Executive Secretary issues a statement declaring an end to the no-burn period.

(ii) The City County Health Department of Utah County has committed itself to adopt local regulations which mirror those which are promulgated with this plan. The Board of County Commissioners of Utah County has adopted a resolution which supports the implementation of a woodburning control program in Utah County, and a copy of that resolution is contained in the technical support document. The regulations adopted by the City-County Health Department of Utah County will be formally adopted into this SIP after they have been formally submitted to the UACC.

(iii) The Utah County Commission on Clean Air has submitted a plan which is incorportated by reference into this SIP and is contained in the Technical Support Document, and which proposes the following programs be established by appropriate local government agencies in Utah County:

(a) Banning of Coal Burning.

The county proposes a ban on all forms of residential coal burning within the County. This could result in a further decrease of 30%, or an additional 0.4 $\mu g/m^3$.

(b) Installer and operator training programs for residential solid fuel burning devices.

A 5% reduction credit for this program is included in the "no-burn" period program.

(c) Solid fuel burner inspection program.

A 5% reduction credit for this program is included in the "no-burn" period program.

(d) Weatherization Requirements for Homes.

Allowable EPA credits for the implementation of requirements regarding the proper weatherization of homes has a maximum reduction of 5 percent. The state is claiming a 2% reduction in space heating emissions.

(v) All of the above strategies (a)-(d) are used as support for the adoption of the solid fuel burning device control strategy, and are used to justify the target 83% emission reduction credit claimed in this SIP.

(vi) In 2001, the actual effectiveness of the woodburning control program was evaluated by comparing PM10 filter data used in the original SIP to filter data collected during a 1996 episode of elevated PM10 concentrations. The 1996 filter data was run through an updated CMB modeling analysis to determine what portion of mass was attributable to woodsmoke. The 1996 apportionment was compared to the original apportionment analysis, and the observed decline in woodsmoke contribution was 83%. Thus, the program has been far more effective in reducing PM10 concentrations during episodes of elevated concentrations than was originally envisioned. This analysis is documented in Supplement II-02 of the Technical Support Document.

b) Primary particulate emissions from solid fuel burning devices in the Salt Lake/Davis County area account for up to 27.0 µg/m3, which is equivalent to 16.03% of the PM_{10} concentrations in this area. The following control strategies will be used to reduce emissions from wood burning devices in the Salt Lake nonattainment area:

i) Paragraph 4.13.3, UACR, establishes mandatory no burn periods for all of Salt Lake County and for areas in Davis County which are south of the southern-most border of Kaysville when the ambient concentration of PM_{10} reaches 120 µg/m3 and the forecasted weather includes a temperature inversion which is predicted to continue for at least 24 hours. During these mandatory no burn periods, it will be unlawful for individuals to use any solid fuel burning device or fireplaces except those which are registered with the Bureau of Air Quality or the local health district office as being the sole source of heat for the entire residence or devices and fireplaces having no visible emissions.

ii) Rules adopted by the Salt Lake City-County Board of Health and Davis County Board of Health which incorporate the regulations adopted by the State will be included into this SIP when they have been received from the county.

c) The following control strategies will be implemented to reduce emissions from residential solid fuel burning devices in all PM_{10} nonattainment areas:

i) Enforcement of the mandatory no burn period will involve an intensive effort from both the Bureau of Air Quality and the local health departments. During the mandatory no burn periods, 8 inspectors from the BAQ will conduct round-the-clock inspections. When a device or fireplace is observed burning, the inspectors may at reasonable times contact the individuals and inform them of the potential violation. The individuals using the fireplace or device may also be informed at that time of the BAQ penalty policy. The inspector will note the address of the observed burning devices or fireplaces. The following day the inspector will determine if the individuals who were burning the previous night are first time or repeat offenders and as soon as possible (within 24 hours), the inspector will implement the provisions of the penalty policy.

ii) The enforcement will also include the investigation of calls received at either the BAQ or the local health department. After a call is received, an inspector will visit the address of the suspected offender and verify if there is actually a violation of the mandatory no burn period. The individual will be contacted and notified of the possibility of penalties. The inspector will return to the office and determine if the individual is a first time or repeat offender and the inspector will implement the provisions of the penalty policy.

iii) Because the Bureau of Air Quality will have the primary responsibility to notify the public of the existence of a mandatory no burn period, the Bureau will reach an agreement by July 1, 1992 with the various news media to ensure that the public is informed of the mandatory no burn periods. A discussion of the media cooperation effort will be included in the technical support document when it is completed.

iv) To provide for a coordinated enforcement mechanism for the provisions of the mandatory no burn period, the Bureau will negotiate enforcement agreements by May 15, 1992, with the offices of the respective county sheriffs, the county fire marshals, the local fire departments, the local law enforcement agencies of each incorporated municipality, and the local city, county or district health departments.

v) To strengthen the enforcement capabilities of the local health officers and alleviate any additional burden which penalization of those found in violation of the local county ordinances may have on the court system, the BAQ will work in cooperation with the local health officials to seek a statutory change to allow the assessment and collection of administrative penalties by the local health departments for woodburning violations.

vi) The implementation of the mandatory no burn period in Salt Lake County and the affected areas of Davis and Utah Counties by the BAQ and the local health department will result in a 60% decrease in emissions from wood burning devices.

vii) Beginning in the spring of 1992, the BAQ will concentrate on the development of a public awareness (PA) program. The program will be geared towards informing the public of the wood burning regulations, the proper installation and operation of solid fuel burning devices, the use of clean fuels, the health effects of wood burning, and the advantages of using a EPA Phase II certified stoves or natural gas. This PA program will be accomplished by using pamphlets, seminars, a booth at the State Fair, and having public discussions on the television and in the newspapers.

viii) The penalty policy which was adopted by the UACC in R446-4 of the Utah Air Conservation Regulations is used by the Executive Secretary to determine penalty amounts to be placed on air pollution sources for violations of the UACR. Category D. of this policy allows for up to \$299 to be assessed against private citizens for non-compliance to the UACR, including the wood burning regulations.

The following guidelines will be followed for violations and penalty amounts:

Violation	**Penalty/Violation**
(a)First Violation	Assess Penalty \$0 -\$25 Issue a NOV
(b)Second Violation	Assess Penalty \$50 - \$150 Issue a NOV
(c)Third Violation	Assess Penalty \$150 - \$299 Issue NOV

Sites found with solid fuel burning devices and fireplaces operating illegally during a mandatory no-burn period will be reinspected within 24 hours and issued another notice of violation (NOV), if still not in compliance.

d) Emissions from coal burning stoves can be significant. For example, they account for 0.3% or 0.08 µg/m^3 of the PM_{10} impact at the Lindon monitoring station. The mandatory no burn period will also preclude the use of coal burning stoves unless they are the sole source of heat, and after 1993, the use of coal stoves will be precluded unless they are able to operate with no visible emissions. The mandatory no burn will result in a 83% reduction of the emissions from coal burning stoves, or 0.07 :g/m^3.

(5) PROVO CANYON CLOSURE TO TRUCK TRAFFIC

The Utah Department of Transportation (UDOT) is in the process of upgrading the Provo Canyon road into a four lane highway. The Provo Canyon Coalition is advocating that all non-destinational heavy duty truck traffic be banned from Provo Canyon. The coalition hired TRC Consultants to do a study of the situation. A copy of that study is contained in the Technical Support Document. Review of the study indicates that it is necessary to evaluate and consider this issue further before any action is taken by the UACC to recommend to the appropriate agency that they limit the use of the canyon by heavy duty diesel trucks. However, based on information currently available to the Committee, the Committee recommends that all non-destinational heavy duty truck which are on the interstate system should remain on the interstate system. The Committee also recommends at this time that the Utah Department of Transportation work with the Bureau of Air Quality to perform the necessary studies to determine the impact which heavy duty diesel truck traffic in Provo Canyon has on the air quality in Utah County and the impact which it would have were it moved to Salt Lake County.

(6) DIESEL INSPECTION AND MAINTENANCE PROGRAM

a)

i) Davis, Salt Lake, and Utah counties for purposes of PM_{10} attainment are required to implement a Diesel Inspection and maintenance (I/M) Program consistent with the provisions of the PM10 SIP. The Davis, Salt Lake, and Utah county Diesel I/M ordinances will be included as appendices and will be part of the PM10-SIP. Utah county's draft I/M Program Ordinance is included now. The Salt Lake and Davis county Diesel I/M Program Ordinance will be added when available.

Diesel I/M is a relatively new pollution control measure nationwide. New data and methods of diesel emission control will be evaluated as they become available. This program will be modified as more effective methods are identified. Any changes adopted will be in accordance with Utah's commitment to a 20% reduction in diesel particulate

ii) This program is designed to ensure compliance with the emissions standards of the Utah Air Conservation Regulations (R466-1-4) regarding diesel engines. Relevant sections are cited below.

4.2.4 Emissions from diesel engines manufactured after January 1, 1973 shall be a of a shade or density no darker than 20% opacity, except for starting motion no farther than 100 yards or for stationary operation not exceeding 3 minutes in any hour.

4.2.5 Emissions from diesel engines manufactured before January 1, 1973 shall be of a shade or density no darker than 40% opacity, except for starting motion no farther than 100 yards or for stationary operation not exceeding 3 minutes in any hour.

4.2.6 Upon application, exceptions to paragraph 4.1.4 and 4.1.5 may be granted by the committee on a case by case basis for diesel locomotives operating above 6000 feet MSL.

iii) In addition to the health hazards associated with PM10 pollution in general, diesel particulate in mutagenic, carcinogenic, and toxic. Furthermore, diesel emissions are generally emitted into the breathing zone of the atmosphere. Once inspired into the lung, diesel particulates, because of their very small size, are not easily removed by the body. The toxic hydrocarbon fraction carried on the elemental carbon fraction is easily released and may react with lung tissue or be absorbed in the blood stream. The significant health threat presented by excessive levels of diesel PM10 make adoption of stricter control measures prudent.

iv) This program is being adopted as one element of a strategy to satisfy federal legal requirements regarding attainment of PM10 National Ambient Air Quality Standards. This standard is violated currently in Salt Lake and Utah counties with impacts from Davis county. Diesel engines contribute significantly to the ambient PM10 concentration along the Wasatch Front, primarily in Davis, Salt Lake, and Utah counties. As a significant contributor to the violations, diesel vehicles must be maintained and operated in such a manner as to minimize their particulate emissions.

v) Owners of gasoline vehicles have been subject to a mandatory inspection and maintenance program in Davis, Salt Lake, and Utah counties for a number of years. Implementation of a diesel inspection and maintenance program is considered by many to be an issue of public perception of equity.

b) DIESEL INSPECTION AND MAINTENANCE (I/M) PROGRAM ELEMENTS

i) DIESEL I/M PROGRAM IMPLEMENTATION

This Program will be implemented in counties that impact PM_{10} nonattainment areas. Said counties will hereafter be referred to as Diesel I/M counties. All diesel-fueled vehicles registered or principally operated in Diesel I/M counties will be required to comply with the provisions of this program. Specific details of the Diesel I/M Program Elements will be established by the Utah I/M Board consisting of health department representatives of each Diesel I/M county and the Bureau of Air Quality using input from the public and other interested parties. The program will be implemented and managed by the local health department in each Diesel I/M county. The Diesel I/M DEC Program will be dynamic and allow for revision of the elements below, as more effective diesel emission control technologies and testing procedures are identified.

ii) MANDATORY MAINTENANCE

Proper maintenance of diesel vehicles is paramount to minimizing air pollution from these sources. Repair of the emission-related components of failed vehicles will be mandatory, to the extent necessary to achieve compliance with opacity standards established pursuant to this SIP. The Mobile Source Division of the California Air Resources Board conducted a study of smoke opacity inpections of urban transit buses with respect to the frequency of emissions related maintenance. They found that frequent periodic smoke inspections are more effective than mandatory engine maintenance schedules for reducing the number of excessively smoking buses in operation.

A county-certified Diesel I/M mechanic will certify, by means of a repeated opacity test, that mandatory emission-related repairs have brought the vehicle into compliance. Repairs may include air and fuel filter replacement, adjustment of primary emission-related engine components to the manufacturer's specifications, replacement or repair of any missing or damaged manufacturer-installed emission control equipment, and repair or replacement of emission-related engine components not functioning per the manufacturer's specifications for the number of miles on the odometer.

iii) Diesel I/M DOCUMENTATION

Documentation of compliance with the Diesel I/M Program requirements consisting of a Diesel I/M Certificate of Compliance or Waiver will be required for annual diesel vehicle registration in Diesel I/M counties.

To facilitate roadside enforcement, proof of Diesel I/M Program compliance in the form of a sticker may be required to be displayed on the vehicle windshield of diesel vehicles registered or principally operated in Diesel I/M counties.

Sufficient data to evaluate the effectiveness of the Diesel I/M Program will be recorded by mechanics on Diesel I/M Reports. These reports will be submitted to the appropriate Diesel I/M county health department. An automated and/or computerized management system will be utilized. Standardized data elements will be certified by the Utah I/M Board.

iv) DIESEL I/M MECHANIC AND STATION CERTIFICATION

Diesel I/M county health departments will certify Diesel I/M mechanics and stations upon their demonstration of adequate training, skill, and resources. Specific requirements for Diesel I/M certification will be explicitly defined by the Utah I/M Board.

Diesel I/M counties will provide Diesel I/M Program training to mechanics, diesel repair facility managers, and other interested parties. The training will include Diesel I/M test procedures, visual opacity training, a description of the components of diesel emissions and their impact on human health and the environment, technical aspects of repair specific to reduction of diesel emission opacity, mechanic and station Diesel I/M program responsibilities and, Diesel I/M Program rules may result in revocation of suspension of certification.

All Diesel I/M county-certified DEC mechanics and stations will be subjected to at least monthly audits and one covert audit each year. Evidence of inadequacy may result in more frequent audits of individual mechanics or stations. An appropriate substitute for covert audit of self-certifying fleet mechanics and stations will be included in the Program. Violation of the Diesel I/M Program rules may result in revocation or suspension of certification.

v) OPACITY COMPLIANCE

(a) Heavy Duty Diesel Vehicle Opacity Test Requirements

Heavy duty diesel vehicle compliance with diesel emission opacity standards will be determined for purposes of registration by means of the "snap idle" test developed by the California Air Resources Board (CARB). The "snap idle" test consists of measuring peak exhaust smoke levels as the accelerator pedal is rapidly depressed while the vehicle transmission is disengaged. Opacity will be measures by means of an opacity meter and recorded on a recording device. The Utah I/M Board will establish specifications for the test, the opacity meter, safety requirements, and test documentation.

A cutpoint of 40% opacity has been shown to result in no greater than 5% errors of commission or omission. The peak smoke certification value was found to be subject to a standard deviation of 10% when production variability within the engine family, deterioration factors, test variability, and state of maintenance were considered.

A limited number of engine families were certified with relatively high peak smoke opacities and may be incapable of achieving "snap idle" opacities below 40%. The Utah I/M Board will establish a procedure to allow a higher opacity standard for these engines families. The owner must submit proof of engine peak smoke certification, make, and horsepower to the appropriate Diesel I/M county office in order to be considered for a waiver of this type.

(b) Light Duty Diesel Vehicle Opacity Requirements

Light duty diesel vehicle exhaust opacity will be measured under load on a dynamometer with an opacity meter and recording device. An opacity cutpoint for light duty diesel vehicles will be established at a value sufficient to achieve a failure rate sufficient to ensure a 10% diesel particulate reduction. The Utah I/M Board will establish specifications for the test, the opacity meter, the recording device, the dynamometer, safety requirements, and test documentation.

(c) Diesel Vehicle Roadside Opacity Enforcement Requirements

Roadside opacity compliance inspection/evaluation and citation of violators by law enforcement officers would be most effectively accomplished by means of a modified EPA Method 9 visual inspection/evaluation to be designed by the Utah I/M Board. The Bureau of Air Quality will seek a Memorandum of Understanding (MOU) with State and local law enforcement agencies to enforce the roadside opacity limits. Training would be provided to law enforcement officers, certified Diesel I/M mechanics, and Diesel I/M auditors for performing this compliance function.

vi) FLEET SELF-CERTIFICATION

Fleets of 10 or more heavy duty diesel vehicles may be self-certified if both the fleet mechanic doing the inspections and the facility is Diesel I/M Program certified. Self-certifying fleets will be required to perform opacity inspections with an opacity meter and recording device that meets Diesel I/M program specifications. Recording devices from the inspections will be maintained and subject to inspections by county staff during any audits. All fleet stations and mechanics certified to perform Diesel I/M self-certification will be subject to regular inspections by appropriate county auditors. During self-certifying fleet audits, county auditors will review vehicle emissions inspection and maintenance records and inspect a representative sample of vehicles with an opacity meter to verify compliance. Self-certifying fleet vehicles will also be subject to a quarterly snap idle test with visual evaluation of smoke opacity. Vehicles that exceed the 40% opacity limit will be remeasured with an opacity meter and repaired if the meter confirms that the exhaust opacity exceeds 40%. Self-certifying stations will maintain records of specific repairs performed to bring failed vehicles into compliance. As with any certified mechanic or station, violation of the Diesel I/M Program rules may result in revocation of suspension of certification. Operation of self-certified fleet vehicles in violation of section R446-1-4 of the Utah Air Conservation Regulations will be considered a violation.

vii) WAIVER PROVISIONS

Waivers will only be issued in the absence of evidence of tampering with emission control devices installed by the manufacturer. A waiver may be issued on a one time basis only. A minimum of $500 must be spent on emissions related repairs without attaining compliance for waiver eligibility on a light duty diesel vehicle. A minimum of $1500 must be spent on emissions related repairs without attaining compliance for waiver eligibility on a heavy duty diesel vehicle. The Utah I/M Board will establish procedures to ensure that waivers are kept to an absolute minimum.

viii) ADDITIONAL STRATEGIES

The Utah I/M Board will evaluate and adopt into the Program, as appropriate, additional strategies regarding fuel specifications, emission control technology retrofitting, locomotive emission control requirements, idling ordinances, participation by commuters from outside the Diesel I/M counties, and alternative fuels. The Utah I/M Board may submit to appropriate federal authorities the recommendation that federal standards regarding control of diesel emissions from interstate be adopted.

ix) PUBLIC AND DIESEL INDUSTRY EDUCATION

Public education regarding Diesel I/M Program requirements and the anticipated environmental benefits will be provided to diesel vehicle owners. A period of intense public education will precede roadside enforcement of the opacity rules. The education effort will include informing drivers of operating practices and the fuel types that increase pollution and should be avoided.

A written summary of the new Diesel I/M Program will be provided to diesel industry organizations with encouragement for inclusion of the information in their publications.

A resource, such as the telephone number of county I/M technical centers, for obtaining additional information will be provided.

x) ENFORCEMENT

The Utah Air Conservation Regulations as applicable to diesel engine emissions standards (R446-1-4 4.1.4-6) and the Diesel I/M Program will be strictly enforced. Pursuant to the authority of Utah Traffic Code 41-6-147 motor vehicles are required to comply with emissions requirements. The Utah Highway Patrol is authorized to cite drivers of vehicles emitting excess diesel smoke or being operated in a Diesel I/M county without a Diesel I/M sticker on the windshield.

Notice of diesel opacity violations will be provided to appropriate railroad offices following observation of excessive locomotive exhaust by an observer that has successfully completed the BAQ smoke evaluation school. A mechanism to verify that the locomotive is repaired to compliance will be established.

County Diesel I/M auditors may on a random basis subject heavy duty diesel vehicles operated in that county to an opacity test conducted at their base of operation. Vehicles for which the county Diesel I/M office has received complaints of excessively smoking diesel vehicles will be subject to an opacity test of the vehicle(s) in question by the auditor. Owners of vehicles found to be in violation of the standard will be penalized as noted below.

The Utah Air Conservation Act 26-13-18(a), provides for imposition of penalties of up to $10,000 per violation of the Act. Penalties for violation of this Program may be levied by authority of the Utah Air Conservation Regulations Penalty Policy, R446-4, 4.A, under which violation of automobile emission standards and requirement is a category D violation and may result in a penalty of up to $299 per violation. The Utah I/M Board will evaluate the penalty policy with respect to the Diesel I/M Program. Penalties should be sufficient to ensure that it is cheaper to fix the vehicles than to risk citation. Repair of smoking diesels, especially heavy duty vehicles frequently exceeds $500 and may cost as much as $10,000. Should the Utah I/M Board evaluation demonstrate the necessity for higher penalties, they will request that the Utah Air Conservation Committee consider revision of the penalty policy accordingly. However, the goal of the Diesel I/M Program is to reduce emissions by inspection and maintenance of vehicles, not to assess penalties.

The Bureau of Air Quality and Diesel I/M counties will initiate an effort to obtain enforcement support from various law enforcement agencies. Diesel I/M county ordinances/rules/regulations authorizing their Diesel I/M Program will include provisions that provide for county enforcement of the requirements of said legal instruments. The Utah I/M Board will recommend to the UACC and counties that they seek statutory change to allow Diesel I/M county imposition of the state and county opacity standards. The penalties allowed should include provisions for removing vehicles with repeat violations from service in Diesel I/M counties.

A significant portion of the heavy duty diesel vehicles operated in Utah's PM10 nonattainment counties are registered outside the state. The Bureau of Air Quality and Diesel I/M counties will initiate an effort to obtain legislative authority to allow the Bureau of Air Quality, Department of Transportation, and Highway Patrol, and Diesel I/M counties to cooperatively develop and conduct a diesel emission roadside smoke opacity port-of-entry inspection program with effective and resonable penalties. The purpose of these inspections would be to identify and subsequently force repair of heavy duty diesel-fueled vehicles that are emitting smoke in excess of Utah's opacity regulations.

xi) Diesel I/M PROGRAM EFFECTIVENESS EVALUATION

Pending availability of funds from EPA or elsewhere, the Utah I/M Board, with the cooperation of local diesel engine maintenance facilities, will conduct a Diesel I/M Program pilot study. A number of vehicles will be selected on a voluntary basis to undergo the proposed inspection and maintenance. Opacity measurements utilizing an opacity meter and recording device will be made before and after repair of failed vehicles to establish a quantitative basis for projected reductions.

The Utah I/M Board will establish a method to support anticipated emission reductions achieved by the Diesel I/M Program. The evaluation will consist of an analysis of data submitted on Diesel I/M Maintenance Reports, a field study to correlate actual opacity reductions with the required inspection and maintenance, modeling evaluations, and actual monitoring station data. A summary of an annual evaluation of current diesel control technology and strategies and recommended Diesel I/M Program changes will be included. A written report of the annual Diesel I/M Program evaluation will be submitted to BAQ/UACC/EPA and Diesel I/M county Health Departments by August 1 of each year after the PM10-SIP regulations are adopted. The program will be reviewed and updated in light of the annual evaluation as deemed effective and reasonable by Diesel I/M county Program Managers.

xii) DIESEL VEHICLE AIR POLLUTION FEE

The Diesel I/M counties will take immediate action necessary to begin assessing an annual Air Pollution Fee of $10 payable upon registration of a diesel vehicle in a Diesel I/M county. The fees will be used by the Diesel I/M counties to develop and implement the Diesel I/M Program.

xiii) Implementation Schedule

June 8, 1990 . . . Utah I/M Board Preparation of an Initial Draft of the Diesel I/M Program Elements

June 13, 1990 . . . Draft Diesel I/M Program Elements Ready for UACC

June 22, 1990 . . . Air Conservation Committee Consider the Draft Elements for Public Hearing

Aug 10, 1990 . . . Utah I/M Board Submit Draft of Diesel I/M Program to BAQ

Aug 15, 1990 . . . Public Hearings for PM10 SIP Including Draft Diesel I/M Program

Sept 15, 1990 . . . Utah I/M Board Finalizes proposed Diesel I/M Program for Submission to UACC and county commissions

Sept 30, 1990 . . . Diesel I/M County Commissions Commit to Implement a Diesel I/M Program by July 1, 1993 that will reduce ambient diesel particulate by at least 20% whether by the test methods described in section b) of the UTAH DIESEL I/M PROGRAM portion of the PM10 SIP or more effective procedures that may be identified during the Implementation Evaluation to be Conducted by the Utah I/M Board between Sept 30, 1990 and Sept 30, 1991.

Oct 1, 1990 . . . PM10 SIP-Regulations for Utah County and parts of Salt Lake and Davis Counties are Sent to EPA for Approval

Nov 1, 1990 . . . Begin Diesel I/M Pilot Study Program (if funds available) and initiate Public and Diesel Industry Education Program

July 1, 1991 . . . Written Notification to Diesel Industry Organizations and Publications

Jan 1, 1991 . . . Diesel I/M Counties Begin Assessing $10 Air Pollution Control Fee Upon Every Diesel-Powered Motor Vehicle Registered

Dec 1, 1991 . . . Draft of Diesel Emission Opacity Inspection Technology Report of Diesel I/M Implementation Evaluation Complete (Include Recommendations for Diesel I/M Program Revision)

May 1, 1992 . . . Emission Opacity Inspection Technology Report Complete (Include Recommendations for Diesel I/M Program Revision)

Sept 30, 1992 . . . County Commissions Approve Diesel I/M Ordinances that Adopt the provisions of section b) of the UTAH DIESEL I/M PROGRAM portion of the PM10 SIP, DIESEL INSPECTION AND MAINTENANCE I/M PROGRAM ELEMENTS, amended as necessary to reflect more effective diesel emission test procedures identified by the Utah I/M Board during the Diesel I/M Implementation Evaluation and approved by the UACC.

Sept 30, 1991 . . . Diesel I/M Program Opacity Limit Warning Signs in place

Oct 30, 1991 . . . Diesel I/M Program Orientation Available to Law Enforcement Agencies

Nov 1, 1991 . . . Enforcement of Opacity Limits by Law Enforcement Officers

Apr 1, 1993 . . . Begin Mechanic and Station Certification

July 1, 1993 . . . Fleet and Public Diesel I/M Program Provisions Become Effective

1993/Quarterly . . . Periodic Preliminary Data Analysis and Evaluation Reports to Diesel I/M-HD/BAQ/UACC/EPA

Dec 10, 1994 . . . Begin Aggressive Enforcement of Diesel Inspection and Maintenance Program Provisions

Dec 10, 1994 . . . 1st Annual Diesel I/M Program Report Provided to Diesel I/M - HD/BAQ/UACC/EPA

Dec 1, 1994 . . . Revision of Diesel I/M Program Regulation(s) Completed, if Appropriate

IX.A.6.g. ROAD SALTING AND SANDING

Road salting and sanding and re-entrained road dust account for up to 16.8 $\mu g/m^3$ of the observed PM_{10} concentrations in Utah County on the design day and up to 13.4 $\mu g/m^3$ at the Salt Lake nonattainment Area monitors. The controlling of road salting/sanding has been reviewed as a source of PM_{10} emissions reductions. The Utah Air Conservation Regulations were changed as a part of the development of this plan to limit the application of de-icing/deslicking material on roads in any PM_{10} nonattainment area to salt containing no more than 2% insoluble solids and the application of sand or crushed slag of which no more than 10% could pass through a #16 mesh, which contained no more that 3% fines, and had a Vicker's Hardness of 1000+. This regulation was predicted to reduce the emissions from road dust and road salting and sanding by 20%.

In response to comments received at the public hearings for this SIP, it was determined that it was essential for the State to gather more information in order to confirm the 20% reduction. The proposed rules were changed to eliminate the limitations on salt/sand/slag applied during the winter of 1991-1992, although it still requires the maintainance of records of the amount and type of material applied be maintained and made available to the Executive Secretary. During the late fall and early winter of 1990 and in the early winter of 1991/1992, EPA and the State committed to fund a study whereby data would be collected to determine the background concentrations of re-intrained road dust and the amount of salt/grit left on the road system after application to verify the 20% reduction claim.

With the study pending it was agreed that, within 6 months of the completion of the study, all agencies responsible for the application of salt, sand, or other deslicking grit to any roadway in a PM_{10} nonattainment area would submit to the UACC for its approval and incorportation into this SIP a plan and implementation schedule which will establish methods which will be used to reduce initial street loading of particulate matter by 25% from the amount applied during the 1989 base year, e.g., by using sand containing a lower percentage of fine material, using more durable grit or sand material, applying street cleaning methods, being more restrictive on the amount of material applied, or any other method aproved by the UACC. Those methods included in the Plan were to have been implemented within 6 months of the submittal of the plan, but no latter than October 1, 1993.

As a result of the study, the use of salt that is at least 92% sodium chloride has been determined to be Reasonably Available Control Technology for salting, and R307-1-3.2.7 has been revised to require that anyone using any other substance must either demonstrate that the material contributes no more PM10 emission than salt that is at least 92% sodium chloride, or must vacuum sweep every arterial roadway to which the material was applied within three days of the end of the storm. The rule as revised no longer requires the submittal of a plan and schedule to reduce street loading of particulate matter by 25%, nor does it require an annual submittal of verification of compliance.

As authorized by Section 19-2-104 of the Utah Code, and as the enforcement mechanism of this regulation, the BAQ will require the maintenance of records of the material applied by those who are responsible for the application of salt/sand/grit to the road system. For salt, the records will include the quantity applied, the percent by weight of insoluble solids in the salt, and the percentage of the material that is sodium chloride (NaCl). For sand or crushed slag the records will include the quantity applied and the percent by weight of fine material which passes the number 200 sieve in a standard gradation analysis. All records must be maintained for a period of at least two years, and the records shall be made available to the Executive Secretary upon request.

IX.A.6.g ROAD SALTING AND SANDING (Utah County, 2002)

Road salting and sanding and re-entrained road dust account for up to 18.2 $\mu g/m^3$ of the observed PM_{10} concentrations in Utah County on the design day. On February 3, 1995, Utah submitted amendments to the PM_{10} SIP to add specifics of the road salting and sanding program promised as a control measure in the PM_{10} SIP. EPA published approval of the road salting and sanding provisions on December 6, 1999 (64 FR 68-31), thus acknowledging that the rule had achieved the 20% target.

SECTION IX.A.7 MAINTENANCE

The preceding demonstrations have shown that the PM_{10} NAAQS will be achieved no later than December 31, 1993. Having once attained the standards it is necessary to maintain ambient PM_{10} concentrations below the standards in order to protect the health of the citizens living in these areas. Eliminating the impact of growth on PM_{10} concentrations is the key to maintaining the PM_{10} NAAQS. Anticipating the areas where growth will occur is difficult and uncertain. The areas where it is anticipated that growth will occur are population; vehicle miles traveled (VMT); home heating; commercial heating; and industrial.

(1) Population is projected to grow at 1.5% per year.

(a) Home heating natural gas furnaces. The growth in natural gas home heating will result in an increase of 1.2 tons/year in PM_{10}, SO_2, and NO_x. A Utah County proposal to establish building code requirements for additional weatherization will reduce the anticipated impact in that county.

(b) Fireplace and wood stove growth. New home construction is 1.5% per year. Information from building permits indicate that 65% to 70% of new homes are constructed with a fireplace or wood stove. An additional 15% to 20% are constructed with the foundation and keyway inplace for a fireplace to be added later. The results of the woodburning surveys in Lindon and Salt Lake indicate that > 30% of those who have wood burning devices are serious woodburners. Most serious wood burners use wood stoves. Federal law prohibits the sale of non-certified stoves after July 1, 1990. The mandatory no burn requirement will restrict the impact of new wood stoves. The exemption that allows only the use of wood stoves and fireplaces with no visible emissions during the mandatory no-burn periods will further limit the increase in woodburning emissions. It is anticipated that the increase in emissions which will occur from the increased number of fireplaces and wood stoves is only 0.2% or 1.2 tons per year.

(2) The vehicle fleet is growing at about 4.5% per year. This growth is also reflected in the increase in vehicle miles traveled and is important to the extent that it identifies the rate at which newer, less polluting vehicles are replacing older, more polluting vehicles.

(3) The number of vehicle miles traveled is projected to increase at a rate of 15% in 5 years. This is a little less than 3% per year. NO_x emissions from automobiles are a major source of secondary PM_{10} in all PM_{10} nonattainment areas. To maintain the PM_{10} standard once it is attained, definite maintenance strategies for automobile emissions must be implemented. There are two possible ways to reduce No_x emissions from automobiles. One method is to reduce the number of vehicle miles traveled (VMTs) and the other method is to actually reduce NO_x emissions from automobile exhaust. Below is a list of the strategies that were evaluated in detail by contacting other state, city and county officials, EPA technical support staff, and evaluating published data on the various strategies. Details on each of the proposed strategies are contained in the technical support document.

The Bureau of Air Quality will consider the recommendations made by the Governor's Clean Air Commission and, in coordination with the local health and planning agencies of the counties along the Wasatch Front, select the most promising and effective strategies to reduce travel related air emissions from those listed below. Those selected strategies will be proposed, legislative action sought as needed, and the appropriate rulemaking completed. This effort began during the summer of 1990 with the goal of obtaining initial legislative action during the CY1991 session and will continue during subsequent sessions of the legislature.

(a) POSSIBLE METHODS TO REDUCE VMTS

PARKING MANAGEMENT:
growth ceilings
increased parking fees

MASS TRANSIT:
bus
light rail system

EMPLOYER-BASED TRAVEL REDUCTION PROGRAMS:
vanpools
flextime
other

NO-DRIVE DAYS:
voluntary

mandatory
only during inversions

BYPASS LANES DURING RUSH HOUR FOR:
bus transit system
carpool
high occupancy vehicles

ENHANCE AND ADVERTIZE THE EXISTING:
bus transit system
ridesharing
park-n-rides
bicycle lanes

IMPROVED LAND-USE PLANNING

GASOLINE RATIONING

(b) POSSIBLE METHODS TO REDUCE NO_x EMISSIONS FROM VEHICLES

ALTERNATIVE FUELS:
implemented for reduction of CO during winter months
many increase NO_x emissions
cng
propane
electric
oxygenated fuels
methanol - ethanol - reformulated gas (mtbe)

REQUIRE USE OF ALTERNATIVE FUELS BY:
public
bus transit system
fleets

IMPROVE TRAFFIC FLOWS:
synchronize lights
maintain continuous flows on interstate

REQUIRE ADDITIONAL NO_x CONTROLS ON VEHICLES:
three-way catalyst converters installed since 1981 retrofitting older cars not feasible

IMPLEMENT NO_x I/M PROGRAM:
additional equipment very costly
NO_x emissions remain constant

IMPLEMENT PROPOSED CLEAN AIR ACT NO_x STANDARD OF 0.4 GPM EARLIER THAN 1993

ADOPT AND IMPLEMENT CALIFORNIA'S PROPOSED NO_x STANDARD OF 0.2 GPM

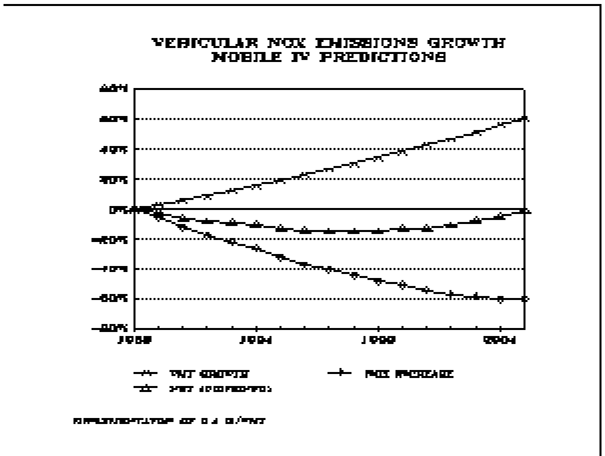


Figure IX.A.22.

(c) It appears that the following proposed maintenance strategy can be implemented without legislative approval which will furnish considerable reduction credits - the Clean Air Act Amendments of 1990 change the existing 1.0 grams/vehicle mile traveled (g/vmt) No_x standard to 0.4 g/vmt, which represents a 60% reduction in vehicle emissions for light duty vehicles which can be claimed by the state as a reduction credit. This Clean Air Act requires cars manufactured after 1994 to meet the more stringent NO_x standard. With cleaner vehicles replacing older more polluting vehicles at a rate of 4.5% per year improvement should continue through the 18 year replacement cycle (i.e., until the year 2012). If analysis of the program and its impact on vehicular emissions indicates that the required emission reductions are not being realized, then the State will evaluate the options to gain the necessary reduction to meet the standard. Figure 9.A.21 shows the impact this proposal will have on vehicular NO_x emissions in the State.

(4) The Utah Department of Transportation and local planning agencies will be requested to cooperate and to review all proposed construction projects for any impact the proposed construction projects will have on the PM_{10} NAAQS and on the strategies included in this PM_{10} SIP as well as those for Ozone and carbon monoxide. Impacts on PM_{10} concentrations should be reviewed and mitigative steps stipulated as part of the planning process.

(5) EPA has promulgated federal standards for diesel fuel. The standard for sulfur is .05% sulfur content of diesel fuel, and is effective in 1993. This is significantly lower than the 0.43% average sulfur content presently in diesel fuel. A standard of 40 C-tane has also been proposed. The implementation of these programs will result in an additional reduction of PM_{10} emissions from diesel engines and will contribute to maintenance of the PM_{10} NAAQS.

(6) EPA has promulgated a federal emission standard for diesel transit bus engines for 1991 and later engines and for heavy duty (8,500 pounds gross vehicle weight and heavier) truck engines for 1994 and later engines. The new diesel emission standards reduce primary PM_{10} particulate emissions by 80% and will reduce NO_x emissions by 50%.

The normal replacement rate for Utah Transit Authority (UTA) buses is 1/12 of their fleet per year. Since a large purchase of 204 buses was made in 1976 and those buses are wearing out, UTA is planning to replace and purchase a number of buses beginning with a replacement of 112 buses in 1990 and plan to replace more buses in 1993 and more in 1998. Beginning in 1991 the normal bus replacement rate will result in a 7% per year reduction in PM_{10} emissions and a 4% per year reduction in NO_x. Documentation from UTA is contained in the technical support document.

The normal replacement rate for truck tractors in the trucking fleet is 20% per year. Beginning in 1994 the new emission standard will result in a 16% per year reduction in PM_{10} emissions for 5 years. The NO_x emissions from diesel trucks will be reduced 10% per year for 5 years. The reduction in PM_{10} emissions from replacement of bus and heavy duty truck engines will contribute to maintenance of the PM_{10} NAAQS. In addition, UTA is purchasing five compressed natural gas buses to research methods of meeting the PM_{10} emission standard.

(7) Commercial growth should follow population growth at 1.5% per year.

a) Local planning agencies are required to review construction projects to assure that the projects are consistent with the SIP and do not create new problem areas or cause a negative impact on an existing problem. Any identified impacts must be mitigated. Since most of the emissions associated with commercial development is associated with boilers or burners for space heating, the emission offset and low NO_x burner requirements will have to be met.

(8) Projected industrial growth is unknown. The PM_{10} standards will be maintained in the PM_{10} group I areas by implementing the following strategies:

(a) Emissions Capping: All sources in existence at the time of the development of this SIP having existing approval orders have been issued new limitations on the emissions of PM_{10}, SO_2, and NO_x. An upper emissions cap has been established for existing industrial sources located in or impacting PM_{10} nonattainment areas.

(b) Emissions Offset: As the population of the valley grows, there are many small sources of NO_x and other PM_{10} matter which will grow without control (i.e., home space heating, space heating of offices, very small boilers, etc.) As a method of verifying that the emissions invenotory stabilizes, any new or modified source located in or impacting the nonattainment areas which emits 25 tons/year or more but less than 50 tons/year of any combination of PM_{10}, SO_2, or NO_x will be required to obtain a 1:1 emission offset credit as a condition of the approval order from the UACC. New or modified sources located in or impacting the nonattainment area which emit 50 tons/year or more of any combination of these pollutants will be required to obtain a 1.2:1 emission offset credit prior to the issuance of an approval order. The result of the offset requirement is that industrial growth will not increase the cap on industrial emissions and a net reduction occurs when larger industries locate in or near the nonattainment areas.

(c) As a minimum, low NO_x burners or whatever is determined to be BACT at the time of proposed construction or modification are required on all new construction. Whenever burners are replaced, low NO_x burners or whatever is determined to be BACT at the time of replacement are required when the replacement can be installed without significant physical changes having to be made on existing process equipment. The result of this requirement will be that new burners will emit 40% to 60% less NO_x than otherwise would be allowed and a 40% to 60% reduction of NO_x emissions will occur when industrial or commercial burners are replaced. The amount of reduction is dependent on the size of the burner being replaced. In addition, if a new burner emits more than 25 tons/year of NO_x, offset of those emissions must be obtained as a condition of the approval order as required in (b) above.

IX.A.7.i Utah County 2002

With this revision to the PM10 SIP, Utah Air Quality Board commits to developing a PM10 maintenance plan or SIP revision, as appropriate, based on dispersion modeling.

SECTION IX.A.8 CONTINGENCY MEASURES

IX.A.8.a. Attainment Date

On 18 June 2001, EPA published a finding (66 FR 32752) that Salt Lake County had attained the NAAQS by 31 December 1995 and Utah County had attained the NAAQS by 31 December 1996. That notice also stated that both areas had demonstrated Reasonable Further Progress as required in the Act (66 FR 32752-754). A letter from EPA Region VIII to the Division of Air Quality dated October 6, 2000 stated that, "In an October 6, 1995 memorandum from Joe Paisie of OAQPS to the EPA regional offices, it was explained that if a PM10 nonattainment area has attained the standard with at least 3 years of clean air quality data, and as long as that area continues to attain the standard, the section 172(c)(9) contingency measure requirement will not apply." Therefore, with eight years of clean air quality data, Utah is not required to submit contingency measures in this SIP. Copies of the Joe Paisie memorandum and the October 6, 2000 letter from EPA to UDAQ are contained in Supplement II-02 of the TSD.

SECTION IX.A.9 ANNUAL AVERAGE

DEMONSTRATION OF ATTAINMENT OF THE ANNUAL AVERAGE

In addition to demonstrating that the 24 Hr. average attains the NAAQS, the SIP must also demonstrate that the annual arithmetic mean meets the NAAQS of 50 µg/m3.

Utah County

The highest annual average PM_{10} concentration over the past two years in Utah County is 54 µg/m^3 for 1988 at Lindon. This results in a required reduction of the annual average of 7.4% in Utah County. On page 6-1, the "PM_{10} SIP Development Guideline" states:

"The SIP-related emission limits should be based on the NAAQS (annual or 24-hour) which result in the most stringent control requirements. For example, if the annual NAAQS requires more stringent control requirements than the 24-hour NAAQS, the annual NAAQS is considered the more restrictive standard and the corresponding emission limit(s) would be adopted."

Since the 24-hour design values result in a reduction of 43% in Utah County, the 24-hour emission limits are the more restrictive.

The application of many of the control strategies that are being implemented to reduce the 24-hour PM_{10} concentrations will also result in a reduction of the annual PM_{10} concentrations even though they are designed to reduce winter time 24-hour concentrations. Table IX.A.26 shows that the winter season is the period that has the greatest impact on the annual average and controlling PM_{10} concentrations during the winter will have the greatest impact on the annual average.

Design values in Utah County ranged from 191 µg/m^3 to
264 µg/m^3. Thus, the control strategy necessary to achieve the 24-hr NAAQS at all stations effectively ranges from 27% to 43%. Even the minimum of this range is well in excess of the 7.4% necessary to bring the maximum observed annual concentration back down to the level of the annual standard. The annual NAAQS for PM_{10} was never violated in Utah County.

1988 (NON-WINTER)	LINDON	WEST OREM	NORTH PROVO
MAR	31		22
APRIL	35		24
MAY	32		31
JUNE	41		25
JULY	47		46
AUG	39		35
SEPT	49		36
OCT	47	34	30
AVG NON-WINTER	40.1		31.1

1988 (WINTER)	LINDON	WEST OREM	NORTH PROVO
JAN	103		75
FEB	98		80
NOV	32	31	23
DEC	96	81	89
AVG WINTER	82.3	56.0	66.8
ANNUAL AVG	54	54	50

1989 (NON-WINTER)			
MAR	39	40	40
APRIL	31	34	29
MAY	32	34	30
JUNE	27	28	29
JULY	39	35	28
AUG	35	29	28
SEPT	35	31	34
OCT	31	29	27
AVG NON-WINTER	33.6	32.5	30.6

1989 (WINTER)			
JAN	119	117	109
FEB	116	122	62
NOV	52	51	42
DEC	75	73	61
AVG WINTER	90.5	90.8	68.5
ANNUAL AVG	52	49	44

Table IX.A.26

Salt Lake - Davis Counties

The highest annual average PM_{10} concentration over the past two years in the Salt Lake - Davis County area is 56 $\mu g/m^3$ for October, 1988, through September, 1989, at the North Salt Lake monitor. This results in a required reduction of the annual average of 10.7 % in Salt Lake County. As stated above, the "PM_{10} SIP Development Guideline" states:

"The SIP-related emission limits should be based on the NAAQS (annual or 24-hour) which result in the most stringent control requirements. For example, if the annual NAAQS requires more stringent control requirements than the 24-hour NAAQS, the annual NAAQS is considered the more restrictive standard and the corresponding emission limit(s) would be adopted."

Since the 24-hour design values result in a reduction of 19.6% in the Salt Lake - Davis County area, the 24-hour emission limits are the more restrictive.

The application of many of the control strategies that are being implemented to reduce the 24-hour PM_{10} concentrations will also result in a reduction of the annual PM_{10} concentrations even though they are designed to reduce winter time 24-hour concentrations. Table IX.A.25 shows that the winter season is the period that has the greatest impact on the annual average and controlling PM_{10} concentrations during the winter will have the greatest impact on the annual average.

As shown in Tables IX.A.17, IX.A.18, and IX.A.19 (attainment demonstration, AMC), the control strategies that will be implemented in Salt Lake County will reduce the winter time 24 Hr. PM_{10} concentrations by 19.6%. Those strategies implement control measures which will reduce PM_{10} concentrations throughout the entire year by 16.9 to 18.6%. The control measures identified in the SIP to reduce 24-hour PM_{10} concentrations during the winter will result in a reduction of 22.5 $\mu g/m^3$ in the annual average, and result in a predicted annual average of 33.5 $\mu g/m^3$ (56-22.5). Additional control requirements have been put into place which will reduce PM_{10} emissions from industrial sources that operate only during the summer. Those controls include a reduced opacity limit on combustion and process sources, increased watering and control requirements on stockpiles and fugitive dust sources and a higher moisture content in process material. In addition more restrictive emission limits have been placed on SO_2 and NO_2 emissions from asphalt batch plants in the North Salt Lake and Beck Street areas which are very near the North Salt Lake PM_{10} monitoring station. Those summer controls in conjunction with the winter control measures for PM_{10} will result in an annual average below the annual NAAQS of 50 $\mu g/m^3$.

1988					
Non-Winter Months	**AMC**	**NSL**	**SLC**	**CW**	**MG**
MAR	35	32	34		
APRIL	42	25	42		
MAY	44	30	31		
JUNE	49	38	36		
JULY	51	36	39	45	
AUG	53	36	39	40	
SEPT	56	57	39	39	
OCT	66	46	28	31	

AVG Non-Winter	49.5	38.6	36.0	37.2	
Winter Months	**AMC**	**NSL**	**SLC**	**CW**	**MG**
JAN	69	72	43		
FEB	70	66	50		
NOV	34	31	25	19	
DEC	80	79	77	48	
AVG (Winter)	63.3	62.0	51.0	40.0	
ANNUAL AVG	54	49	41	38	
1989					
Non-Winter Months	**AMC**	**NSL**	**SLC**	**CW**	**MG**
MAR	51	43	34	34	25
APRIL	32	46	26	29	24
MAY	33	42	26	28	21
JUNE	27	29	26	36	19
JULY	37	51	32	41	29
AUG	37	47	26	44	25
SEPT	37	54	31		29
OCT	36	58	29		25
AVG Non-Winter	36.3	46.2	28.8	35.3	24.6
Winter Months	**AMC**	**NSL**	**SLC**	**CW**	**MG**
JAN	91	75	99	105	47

FEB	100	79	83	68	56
NOV	59	64	42		34
DEC	83	80	78	87	47
AVG (Winter)	83.3	74.5	75.5	86.6	46.0
ANNUAL AVG	51	56	41	55	31
1990					
Non-Winter Months	**AMC**	**NSL**	**SLC**	**CW**	**MG**
MAR	33	36	25	27	21
APRIL	26	35	20	20	20
MAY	29	35	21	21	16
JUNE	31	40	22	22	20
JULY	35	46	26	45	25
AUG	35	53	33	40	29
SEPT	31	49	28	39	24
AVG Non-Winter	31.4	42.0	25.0	25.6	22.1
Winter Months	**AMC**	**NSL**	**SLC**	**CW**	**MG**
JAN	55	55	42	37	29
FEB	50	39	43	28	
AVG (Winter)	52.5	52.5	40.5	40.0	28.5

SECTION IX.A.10 TRANSPORTATION CONFORMITY

For purposes of Transportation Conformity as established by Section 176(c)(2)(A) of the Clean Air Act, Table IX.A.28 identifies the mobile source budget for 2003 and the two horizon years used in transportation planning, 2010 and 2020 for Utah County:

Year	Tons/Winter Day	
	Primary PM	NO_x
2003	6.57	20.35
2010	7.74	12.75
2020	10.34	5.12

TABLE IX.A.28

The values for 2003 reflect the inventory values for mobile sources that were used in the CMB modeling. The CMB modeling, based on these inventory values and inventory values for other source categories, demonstrates attainment in 2003.

The inventory values are shown in Table IX.A.3. The CMB modeling results are shown in Tables IX.A.5.a and b, IX.A.7.a and b, and IX.A.9.a and b.

For 2010 and 2020, inventory values for all source categories were projected forward, based on appropriate growth assumptions. The 2010 and 2020 mobile source emissions budgets reflect the mobile source inventory values in 2010 and 2020, except that "road dust" and "brake wear" portions of the 2020 mobile source inventory were expanded by 7% to take advantage of part of the available safety margin in that year. More specifically, even using these expanded mobile source emissions, the CMB projections for 2020 show a maximum concentration of 147.2 ug/m3. Documentation for the assumptions used to establish these budgets and for the modeling used to make this demonstration of attainment is all contained in Supplement II-02 of the Technical Support Document (TSD).

The motor vehicle inventory values were developed by the Mountainland Association of Governments (MAG) based on MOBILE6, PART5, and current projections of the Vehicle Miles Traveled (VMT) in Utah County. The modeling analysis included the most recent planning assumptions concerning point, area, and mobile sources.

MAG is required to develop Long Range Plans that go out well beyond 2020, and to demonstrate conformity to the 2020 budget for all years beyond 2020. Also contained in Supplement II-02 of the TSD is a discussion of possible control strategies that might be employed by MAG to meet these budgets after 2020.

Emission Limitations and Operating Practices (Dated 28 June 1991)

1 General Requirements (Davis and Salt Lake Counties)

2.1.A Stack testing to show compliance with the emission limitations for the sources in this appendix shall be performed in accordance with 40 CFR 60, Appendix A; 40 CFR 51 Appendix M; and Section 3.2.5, UACR. The back half condensibles are required for inventory purposes and shall be determined using the method specified by the Executive Secretary. If after two stack tests are conducted at a particular emissions point under this SIP, it is shown that because of the reliability of pollution control equipment, constant emissions or other appropriate reasons, the stack testing frequency prescribed by these regulations is more frequent than necessary to determine the quantity of emissions, the Utah Air Conservation Committee may reduce the stack testing frequency of any particular emission point in a given year. The following test methods shall be used for the indicated air contaminants:

PM_{10} For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201 or 201a plus the back half condensibles using method 202 (when promulgated by the EPA) or by the method specified by the Executive Secretary.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, 5e, or other as approved by the Executive Secretary as appropriate, plus back half condensibles using method 202 (when promulgated by the EPA) or by the method specified by the Executive Secretary. All particulate captured in the back half shall be considered PM_{10}.

The PM_{10} captured in the front half, as determined by the appropriate method acceptable to the Executive Secretary, shall be considered for compliance purposes.

SO_2 Appendix A, Method 6, 6A, 6B or 6C

NO_x	Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E
Sample Location	Appendix A, Method 1
Vol flow rate	Appendix A, Method 2
Calculations	To determine mass emission rates (lbs/hr, etc.), the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

Notification of the test date shall be provided at least 45 days prior to the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days prior to the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1 and Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location. The production rate during all compliance testing shall be no less than 90% of the production rate at which the facility will normally be operated.

The limitations for the sources listed in Section 2.2 are expressed in terms of PM_{10}, SO_2 and NO_x. The PM_{10} limitations have been converted to PM_{10} from TSP based upon estimated, but unsubstantiated emissions factors. The emissions data used in this Section are based upon the best data available. Nevertheless, the SO_2 and NO_x emissions limitations are also estimated, but are unsubstantiated calculations, conversion factors and emissions factors. SO_2 and NO_x historically have not been measured in specific stacks resulting in a sparsity of reliable data (i.e., the SO_2 and NO_x emissions inventory and resulting emissions limitations may be too high or low). After this PM_{10} SIP becomes effective and at the first regularly scheduled compliance test in accordance with Sections 3.2.5 or 3.2.6, UACR, the emissions limitations as stated herein will be verified as necessary, and readjusted with the approval of the Executive Secretary. The emissions limitations for PM_{10}, SO_2 and NO_x will be adjusted appropriately once the relationship between the old emissions inventory calculations, stack tests and emissions factors and the new test results are understood and verified. Adjustments may be made, provided the adjustments do not adversely affect achieving compliance with the National Ambient Air Quality Standards (NAAQS).

An exceedance of the mass emissions rates (lbs/hr.), concentration limitations (grains/dscf), or both for a single point source during compliance testing shall be considered a single violation during the test period. If an adjustment in the relationship between the TSP base limitation and PM_{10} limitations should be necessary at the first compliance test, individual stack test results will not be considered in violation of the PM_{10} particulate emission limitation if the TSP base value is not exceeded. The base TSP value is the TSP value from which the PM_{10} particulate limitation was calculated as per the SIP Technical Support Document or as indicated in this Section.

Following the final establishment of the PM_{10} particulate, SO_2, and NO_x limitations, the new limitations will be used for enforcement where applicable.

2.1.B Visible emissions shall be as follows except as otherwise designated in specific source subsections: Baghouse applications shall not exceed 10% opacity; scrubber and ESP applications shall not exceed 15% opacity; combustion sources without control facilities shall not exceed 10% opacity; fugitive emissions shall not exceed 15% opacity and fugitive dust, refinery catalytic cracking units, and process flares shall not exceed 20% opacity.

2.1.C Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. For intermittent sources and mobile source emissions opacity observations shall be conducted using a modified method 9 (not all 24 readings for a six minute period required).

2.1.D Compliance with the annual limitations shall be determined on a rolling 12 month total except where specifically exempted or otherwise provided for. Based on the first day of each month a new 12-month total shall be calculated using the previous 12 months.

2.1.E Records of consumption/production shall be kept for all periods when the plant is in operation. Records of consumption/production shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

2.1.F These limitations and operating practices shall replace all language pertaining to particulate, SO_2 and NO_x in approval orders for the listed sources issued prior to the effective date of this Appendix A. All language in the existing approval orders which pertains to other air contaminants shall remain in effect with the approval orders.

2.1.G All installations and facilities authorized by this regulation shall be adequately and properly maintained.

2.1.H Any future modifications to the installation or facilities covered in this regulation must also be approved in accordance with Section 3.1, UACR.

2.1.I All unpaved operational areas which are used by mobile equipment shall be water sprayed and/or chemically treated to reduce fugitive dust. Control is required at all times (24 hours per day every day) for the duration of the project/operation. The application rate of water shall be a minimum of 0.25 gallons per square yard. Application shall be made at least once every two hours during all times the installation is in use unless daily rainfall exceeds .10 of an inch or the road is in a muddy condition or if it is covered with snow or if the ambient temperature falls below freezing or if the surfaces are in a moist/damp condition. If chemical treatment is to be used, the plan must be approved by the Executive Secretary. Records of water treatment shall be kept for all periods when the installation is in operation. The records shall include the following items:

A. Date
B. Number of treatments made, dilution ratio, and quantity
C. Rainfall received, if any, and approximate amount
D. Time of day treatments were made

Records of treatment shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

2.1.J Annual emissions referred at the end of each subsection of Appendix A are not to be used for purposes of determining compliance unless otherwise specified in source specific sections. No modifications to these sources, which would result in an increase of annual emissions, shall be approved without an analysis of the effect on the PM-10 SIP. These annual emissions shall be used in the determinations required for off-set credit, PSD applicability, and nonattainment area major source reviews. These emissions are normally what the source is actually emitting annually.

2.1.K "Test if directed," as used in specific source subsection, shall mean test if directed by the Executive Secretary.

2.1.L The definitions contained in Section 1-1, UACR (Foreword and Definitions), shall apply to this Appendix A.

2.1.M Petroleum Refineries

A. All petroleum refineries in or affecting the PM_{10} nonattainment area shall for the purpose of this PM_{10} SIP 1) require sulfur removal units/plants (SRU) that are at least 95% effective in removing sulfur from the streams fed to the unit, 2) shall not be allowed to burn liquid fuel oil except during natural gas curtailments and/or as specified in the individual subsection of this appendix (allowed as a result of trading off other equal amounts of emission reductions), and 3) require the use of low SO_x catalyst emission reduction techniques/procedures (as feasible on fluid Catalytic Cracking units) which shall result in no more than 9.8 kg of SO_2 per 1000 kg of coke burnoff). The streams from the Amine plants and the sour water overhead stripping operations shall be processed in the SRU.

B. The routine turnaround maintenance period (expected every 2 to 5 years for approximately a 15 day period) for the SRU shall only be scheduled for the April through October periods. The projected periods/forecasts for the SRU turnarounds shall be submitted to the executive secretary by the end of the first calendar quarter of each year planned and 30 days prior to the turnaround a notice shall be given to the executive secretary.

C. Compliance Demonstrations.

1) Neither the emissions increase (above normal operations) experienced during the SRU routine turnarounds nor those from process flaring shall be included in the daily (24 HR) or annual compliance demonstrations.

2) Compliance with the maximum daily (24 HR) plantwide emission limitations for PM_{10}, SO_2, NO_x shall be determined by adding the emissions resulting from the sources listed in the refinery's subsections under the emission cap with those from the listed non-cap sources. The emissions from non-cap sources, excluding those from process flares and sulfur removal units/plants (SRU) during routine turnaround maintenance shall be determined by adding daily CEM measured emissions from the SRU tail gas units to emission estimates for stack tested sources. Estimates for the stack tested sources shall be made by multiplying the latest stack tested hourly amounts times the logged hours of operation for each day. Records shall be kept by the refineries, on a daily basis, of CEM data, fuel gas meter readings, parameters of the used fuel oil, hours of equipment operation, and the calculated emissions. These records shall be made available to the executive secretary or his representative upon request. These records shall be kept for at least one year ending with the date of the request.

3) Any modifications to the metering scheme or changes to the emission factors/equations used by the refineries to calculate emissions must be approved by the executive secretary. It is anticipated that due to the small amount of PM_{10}, SO_2, NO_x emission test results available prior to finalizing this appendix for the PM_{10} SIP, the initial stack testing and emission measurements for two years after the SIP is promulgated by the state may cause a re-evaluation of specific limitations assigned to these sources. As more emission data are available, the emission limitations shall be evaluated by the executive secretary and adjusted, if necessary, based upon the best technical methods and information

available at the time. Any adjustments made must be reviewed as to the effect upon achieving and maintaining compliance with the National Ambient Air Quality Standards (NAAQS).

4. Compliance with the annual PM_{10}, SO_2, NO_x limitations shall be determined on a rolling 12 month total. Based on the first day of each month, the previous month's daily (24 HR) emissions (excluding flare and SRU turnaround emissions), as calculated using the specific refinery emission factors/equations, shall be summed for a monthly total. The annual emissions shall be the summation of the last 12 monthly totals. Records of the monthly and rolling 12 month totals shall be kept and be made available to the executive secretary or his representative upon request. These records shall be kept for at least two years ending with the date of request.

D. Estimated process flaring emissions and SRU routine turnaround emissions were used in the 24 hour and annual demonstration, respectively, of attainment of the NAAQS in the PM_{10} SIP. The flaring and SRU turnaround emissions shall be estimated for each month and be reported as part of the annual emissions referred to in Section 2.1.J of the Appendix. They shall not, however, be used for compliance purposes.

2.2 Particulate Emission Limitations (company specific)

2.2.A Amoco Oil Company, - 474 West 900 North, Salt Lake City

1. The installations shall consist of the following equipment:

	Description	Fuel
A.	Crude unit furnace (H101)	Plant Gas
B.	Ultraformer furnace (F1)	Plant Gas
C.	Regeneration gas heater (F15)	Plant Gas
D.	FCCU and CO boiler (ESP)	Plant Gas & Cat Coke
E.	Boiler plant (BP)	Plant Gas & Fuel Oil
F.	Ultraformer compressors (K1's)	Propane
G.	South Flare	Nat Gas
H.	North Flare	Nat Gas
I.	TLR Vapor Combustor (Standby)	Nat Gas
J.	Sulfur unit tail gas & incinerator (SRU)	Plant Gas Tail Gas
K.	DDU Furnace(s)	Plant Gas

2. The following shall be the basis for SO_2 emissions limitations:

A. Emissions Limitations:

Amoco Oil Company, Salt Lake Refinery's maximum SO_2 emissions to the atmosphere shall not exceed the following:

1) 4.438 tons/day From November 1, through the end of February. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed 3.753 tons per day.
2) 5.326 tons/day From March 1, through October 31. Of this total, SO_2 emissions from all sources included under the emissions cap

shall not exceed 4.504 tons per day.

The annual emission limitation for SO_2 from all sources shall not exceed 1,620 tons. Of this total, the annual SO_2 emissions from all sources included under the emissions cap shall not exceed 1,370 tons.

B. The following sources shall be included in the SO_2 emissions cap:

Source	Fuel
1) Crude Unit Furnace (H101)	Plant Gas
2) Ultraformer Furnace (F1)	Plant Gas
3) Regen. Gas Heater (F15)	Plant Gas
4) FCCU & CO Boiler (ESP)	Plant Gas
5) Coke Regeneration at the FCCU & CO Boiler	Coke
6) Boiler Plant (BP)	Plant Gas
7) Boiler Plant (BP)	Fuel Oil
8) Compressors (K1's)	Propane
9) DDU Furnaces	Plant Gas

C. SO_2 emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relavent quantities of fuel combusted. This shall be performed according to the following:

1) Emission Factors for the various fuels shall be as follows:

natural gas - 0.60 lb/mmscf

propane - 0.60 lb/mmscf

plant gas - the emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor which will measure the H_2S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

(lb SO_2 / mmscf gas) = (24 hr avg. ppmv H_2S)/10^6 * (64 lb SO_2 / lb mole) * (10^6 scf / mmscf) / (379 scf / lb mole)

fuel oil - the emission factor to be used in conjunction with fuel oil combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

(lb SO_2 / kgal) = (density lb/gal) * (1000 gal/kgal) * (wt.% S)/100 * (64 g SO_2 / 32 g S)

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted during periods of natural gas curtailment, and at other times but shall not exceed 200 barrels per day. The sulfur content of the fuel oil shall be tested if directed by the Executive Secretary.

2) Fuel Consumption shall be measured as follows:

Natural gas consumption shall be determined by meters, which shall be installed if necessary, to measure the total quantity of natural gas delivered to the plant.

Propane consumption shall be determined by meters at the outlet of all propane tanks.

Plant gas consumption shall be metered at the FGD meter.

Fuel Oil consumption shall be measured each day by means of leveling gages on all tanks which feed combustion sources.

3) The equations used to determine emissions for the emission cap sources shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas

Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Propane Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Sulfur dioxide emissions from the stack serving the FCCU and the CO boiler shall be limited to a maximum rate of 9.8 pounds of SO_2 per thousand pounds of coke combusted. Compliance with this limitation will be determined by calculating the total flue gas flow rate less the plant gas flow rate to the CO boiler (measured by meter FR-66 and already accounted for at the FGD meter), via metering the combustion air flow rate in the FCC with meter FR-115, and the total stack O_2 content. This flow rate, in conjunction with the SO_2 concentration (measured with a Continuous Emissions Monitor), will then be used to determine the emissions as follows:

(mmscf flue gas / 24 hrs) X (ppmv SO_2) X 0.169 = lb SO_2 / 24 hrs

These emissions will then be compared to the feed rate of coke to determine compliance with the specified emission limit.

5) Total 24-hour SO_2 emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above SO_2 emissions equations for natural gas, propane, plant gas, and fuel oil combustion to the amount of SO_2 attributed to coke combustion. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt.% S, recorded for each day any fuel oil is burned), CEM readings for SO_2 at the FCC/CO Boiler stack (averaged for each one-hour period), combustion air flow rate and O_2 content in the FCC, and the calculated emissions. See

section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

SO_2 emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for SO_2 at the following emission limits:

Point Source	lb/hr	tons/yr	ppmv
Sulfur Plant Incinerator	?????	250	???

The specific limitations will be established in accordance with Section 3.1 UACR.

E. Stack testing to determine hourly, daily, and annual compliance for the non-cap sources described in number 2. D, above, shall be performed as directed in condition number 5 below, and in accordacne with sections 2.1.A and 2.1.M of this Appendix.

Sulfur dioxide emissions from the tail gas of the sulfur plant incinerator shall be calculated from the total mass flow rate of the incinerator stack flue gas, and an on-line Continuous Emissions Monitor.

F. The following sources shall not be regulated for SO_2 emissions, nor shall they be included in the emission limitation totals herein.

1) South Flare
2) North Flare
3) TLR Vapor Combustor (Standby)

3. The following shall be the basis for NO_x emissions limitations:

A. Emissions Limitations:

Amoco Oil Company, Salt Lake Refinery's maximum NO_x emissions to the atmosphere shall not exceed 2.262 tons per day. Of this total, NO_x emissions from all sources included under the emissions cap shall not exceed 1.601 tons per day. The annual emission limitation for NO_x from all sources shall not exceed 688.0 tons. Of this total, the annual NO_x emissions from all sources included under the emissions cap shall not exceed 584.2 tons.

B. The following sources shall be inclused in the NO_x emissions cap:

Source	Fuel	Meter	Emission Factor
1) H101	Plant Gas	FR-5	250 lb/mmscf
2) F15	Plant Gas	FR-70	140 lb/mmscf
3) ESP	Plant Gas	FR-66	140 lb/mmscf
4) ESP	Cat Coke	Feed	71 lb/kbbl
5) BP	Plant Gas	FR-303-6	0.067 lb/mmbtu
6) BP	Fuel Oil	Tankage	0.067 lb/mmbtu
7) K1's	Propane		10 lb/mmscf
8) SRU	Tail Gas		stack test
9) DDU	Plant Gas		* 63 lb/mmscf

C. NO_x emissions for the emission cap sources shall be determined by applying the emission factors identified in the table above to the quantities of fuel combusted in the respective sources, as measured by the indicated meters. The emission factors shall be derived and periodically updated with qualified stack testing.

D. Total 24-hour NO_x emissions for the sources included in the emissions cap shall be calculated by multiplying the emission factor for each source by the respective quantity of fuel or energy consumed, and summing the results for all of the sources. Results shall be tabulated every day, and records shall be kept which include all meter readings (in the appropriate units), plant gas parameters (btu/ft^3 for sources which have emission factors in terms of lb/mmbtu), fuel oil parameters (wt.% S), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

E. Individual Point Source Limitations:

NO_x emission limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for NO_x at the following emission limits:

Point Source	lb/hr	tons/yr
Ultraformer Furnace (F1)	23.7	103.8

F. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 3 E, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

G. The following sources shall not be regulated for NO_x emissions, nor shall they be included in the emission limitation totals herein:

1) South Flare
2) North Flare
3) TLR Vapor Combustor (Standby)

4. The following shall be the basis for PM_{10} emission limitations:

A. Emissions Limitations:

Amoco Oil Company, Salt Lake Refinery's maximum PM_{10} emissions to the atmosphere shall not exceed 0.310 tons per day. Of this total, PM_{10} emissions from all sources included under the emissions cap shall not exceed 0.186 tons per day. The annual emission limitation for PM_{10} from all sources shall not exceed 113.0 tons. Of this total, the annual PM_{10} emissions from all sources included under the emissions cap shall not exceed 68.0 tons.

B. The following sources shall be included in the PM_{10} emissions cap:

Source	Fuel	Meter
1) Crude Unit Furnace (H101)	Plant Gas	FR-5
2) Ultraformer Furnace (F1)	Plant Gas	FR-201 & FR-202
3) Regen. Gas Heater (F15)	Plant Gas	FR-70
4) Boiler Plant (BP)	Plant Gas	FR-303-6
5) Boiler Plant (BP)	Fuel Oil	Tankage
6) DDU Furnaces	Plant Gas	???

C. PM_{10} emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relavent quantities of fuel combusted in each unit. This shall be performed according to the following:

1) Emission Factors for the combustion sources shall be as follows:

plant gas - 5 lb/mmscf

fuel oil - the PM_{10} emission factor for fuel oil combustion shall be determined based on the H_2S content of the oil as follows:

PM_{10} (lb/kgal) = (10 * wt.% S) + 3

2) Daily plant gas consumption for each cap source shall be measured by the respective meters indicated in the table above (or by meters to be installed as necessary).

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks which feed combustion sources. Fuel oil consumption shall be allowed during periods of natural gas curtailment, and at other times but shall not exceed 200 barrels per day.

3) The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Total 24-hour PM_{10} emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above PM_{10} emissions equations for plant gas and fuel oil. Results shall be tabulated every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt.% S), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

PM_{10} emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for PM_{10} at the following emission limits:

Point Source	lb/hr	gr/dscf	tons/yr
(4) ESP	10.3	0.024	45.0

E. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 4 D, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

F. The following sources shall not be regulated for PM_{10} emissions, nor shall they be included in the emission limitation totals herein.

1) Ultraformer Compressors
2) South Flare
3) North Flare
4) TLR Vapor Combustor (Standby)
5) Sulfur Unit Tail gas (SRU)

5. Stack Testing Requirements:

The following point sources have been required to comply with various emission rates and concentrations in the paragraphs preceeding. The following is summary of the testing methods and frequencies appropriate to each point source. The provisions set forth in Appendix A 2.1.A of this document apply to the testing of these listed sources.

A. Crude Unit Furnace

	Limitations	Test Method	Frequency
NO_x	250 lb/mmscf	7	Every 3 yrs.

B. Ultraformer Furnace

	Limitations	Test Method	Frequency
NO_x	23.7 lb/hr	7	Every 3 yrs.

C. FCC & CO Boiler Stack (ESP)

	Limitations	Test Method	Frequency
*SO_2	9.8 lb/klb coke	CEM	Continuous
	* For Coke Regeneration		
*NO_x	71 lb/kbbl	7	If Directed
	* For Coke Regeneration		
PM_{10}	10.30 lb/hr .0240 gr/dscf	201/201a	Every 3 yrs.

D. Boiler Plant (Fuel gas)

	Limitations	Test Method	Frequency
NO_x	0.67 lb/mmbtu	7	If Directed

E. Ultraformer Compressors

	Limitations	Test Method	Frequency
NO_x	10.0 lb/mmscf	7	If Directed

F. Sulfur Unit Tail Gas (Incinerator)

	Limitations	Test Method	Frequency
*SO_2	????? lb/hr ??? ppmv	CEM	Continuous
*NO_x	???? lb/hr ??? ppmv	6	If Directed

*Limits to be established in accordance with UACR section 3.1.

6. Annual emissions for this source (the entire plant) are hereby established at 113 tons/yr for PM_{10}, 2,013 tons/yr for SO_2 (which includes 393 tons for routine sulfur plant down time), and 688 tons/yr for NO_x.

2.2.B Asphalt Materials

1. The installations shall consist of the following equipment located at the site:

   A. Stansteel Model asphalt batch plant serial no. 413, complete with a Standard Havens baghouse Model 21, Alpha Mark V, serial no. 10655

   B. One Loader

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Asphalt plant baghouse (APBH)

PM_{10}	4.79 lbs/hr	0.024	grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the plant exhaust stack emission point and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

	Method	Retest Every
Asphalt Plant Exhaust Stack		
PM_{10}	201/201a	3 year

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 220 tons/hr of asphalt
   B. 160,000 tons/yr of asphalt
   C. 9 hours/day
   D. 1800 hours/yr

   Records of asphalt production shall be determined by scale receipts and hours of operation by an operations log.

5. Devices indicating the following operational parameters shall be installed, operable and accessible for safe inspection:

   A. Differential pressure across the fabric filter dust collector in inches of water gage (in H_2O)

B. Temperature of the gases exiting the fabric filter baghouse in degrees Fahrenheit (°F)

C. Asphalt product production in tons per hour

D. Asphalt product temperature in degrees Fahrenheit (°F)

E. Asphalt oil temperature in degrees Fahrenheit (°F)

They shall be monitored with equipment located such that an inspector can at any time safely read the output. All instruments shall be calibrated against a primary standard at least once every 90 days. The primary standard shall be specified by the Executive Secretary.

6. The moisture content of the raw aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 6.0% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

7. The owner/operator shall use only natural gas as a fuel in the asphalt plant. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

8. Annual emissions for this source (the entire plant) are hereby established at 2.7 tons/yr for PM_{10}, 0.1 tons/yr for SO_2, 2.9 tons/yr for NO_x.

2.2.C Asphalt Materials, - 1075 W 1700 S, Screening Plant

1. The approved installations shall consist of the following equipment located at the site:

   A. Screening plant
   B. Radial Stacker
   C. Two loaders
   D. Generator

2. The following operating parameters shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 350 tons per hour of aggregate screen feed rate
   B. 560,000 tons per year of aggregate screen feed rate
   C. 8 hours per day
   D. 1600 hours per year

   Records of consumption/production shall be kept for all periods when the plant is in operation. Aggregate production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

3. The haul road length shall not exceed 0.25 miles without prior approval in accordance with Section 3.1, UACR. The speed of vehicles on the haul road shall not exceed 20.0 miles per hour without prior approval in accordance with Section 3.1, UACR.

4. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All screens
   B. All conveyor transfer points

   The sprays shall operate whenever dry conditions warrant or as determined necessary by the Executive Secretary.

   Conditions which warrant operation are defined as any time the applicable opacity limitation is going to be violated.

5. The moisture content of the material shall be maintained at a value of no less than 4% by weight. The silt content of the product shall not exceed 8% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by

the Executive Secretary using the appropriate ASTM method.

6. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary.

7. Annual emissions for this source (the entire plant) are currently calculated at 10.2 tons/yr for PM_{10}.

2.2.D Bountiful City Light and Power

1. The installations shall consist of only the following equipment:

   A. 1 - 600 kW Worthington dual fuel engine (engine #1)
   B. 2 - 1,250 kW Superior dual fuel engines (nos. 2 & 3)
   C. 2 - 1,000 kW Superior dual fuel engines (nos. 4 & 5)
   D. 1 - 1,950 kW Cooper Bessemer dual fuel engine (engine #6)
   E. 1 - 110 kW Buckeye dual fuel engine (engine #7)
   F. 1 - 9,750 HP Enterprise dual fuel engine (engine #8)

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. The 9,750 HP Enterprise engine:

1.	NO_x	79.5 lbs/hr	3.70 grams/hp*hr
2.	CO	32.2 lbs/hr	1.50 grams/hp*hr
3.	VOC non methane	15.0 lbs/hr	0.70 grams/hp*hr

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

   The 9,750 HP Enterprise engine:

	Method		Retest every
1.	NO_x	7	3 years
2.	CO	10	Test If Directed
3.	VOC	25	Test If Directed

   The operating rate during all compliance testing shall be no less than 7,312 horsepower (90% of the production rate at which the facility will be operated).

4. Stack testing to show compliance for the engines listed below to determine NO_x and CO emission limitations shall be performed for the following emission points:

   A. 1 - 7600 kW Worthington dual fuel engine (engine #1)
   B. 2 - 1,250 kW Superior dual fuel engines (nos. 2 & 3)
   C. 2 - 1,000 kW Superior dual fuel engines (nos. 4 & 5)

D. 1 - 1,950 kW Cooper Bessemer dual fuel engine (engine #6)

E. 1 - 110 kW Buckeye dual fuel engine (engine #7)

These sources shall use natural gas as primary fuel in all fuel burning furnaces, ovens and boilers. Number 2 fuel oil or better shall be used only as a pilot fuel or backup fuel to be used during natural gas curtailments and for maintenance firing. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UCAR. Fuel consumption shall be determined by gas meter readings and oil receiving and inventory records.

B. On the first day of each month a new 12-month rolling total emissions inventory shall be compiled. The inventory shall be based on the previous 12-month rolling total operation and the appropriate emission factors and engine settings for each engine.

The appropriate emission factors, intake manifold pressure, cylinder exhaust temperatures, and pilot rack settings for each engine shall be established for minimum emissions operation through testing using a portable monitoring system or equivalent. The intake manifold pressure, cylinder exhaust temperatures, and pilot rack settings for each engine shall be used whenever the engine is operated.

If the NO_x emissions exceeds 200 tpy for the previous 12 months, the source shall submit a report of the emissions to the Executive Secretary within 30 days. Within 90 days the source shall submit to the Executive Secretary for approval a plan with proposed specifications for the installation, calibration, and maintenance of a continuous emissions monitoring system (CEMS) for NO_x. The CEM shall be on line within 12 months following the approval of the plan.

5. The total power generated shall not exceed 35,990 MW*hr/yr without prior approval in accordance with Section 3.1, UACR:

6. The following operating parameters shall be maintained within the indicated ranges:

A. For the 9,750 HP Enterprise engine:

1. Intake manifold pressure = (% engine load - 34.53)/1.81. The equation is valid for engine loads within the range of 50 to 100% only. The pressure is measured in inches mercury. The

allowable variation is 1.0 inch.

2. Pilot oil rack setting: For the left side will be maintained at 6.0 mm and for the right side will be maintained at 7.5 mm. The allowable variation will be plus or minus 0.5 mm.

3. Cylinder exhaust temperature = (% engine load - 551) /-0.51, °F. for each cylinder. This equation applies to engine loads within the range of 50 to 100% only. The allowable variation will be plus or minus 75°F for each cylinder.

They shall be monitored with equipment located such that an inspector can at any time safely read the output. The readings shall be accurate to within the following ranges:

1.	Combustion air manifold pressure:	0.1 in. Hg
2.	Pilot oil injection rack setting:	0.5 mm
3.	Cylinder exhaust temperature:	5°F
4.	Energy production:	1 MW*hr

7. A. The owner/operator shall use only natural gas as the primary fuel and number 2 fuel oil or better as the pilot fuel in (any of) the dual fuel engines. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of any fuel oil burned shall not exceed 0.45 weight percent sulfur as determined by ASTM Method D-4294-89. The sulfur content shall be tested if directed by the Executive Secretary.

B. On the first day of each month a new 12-month rolling total emissions inventory shall be compiled. The inventory shall be based on the previous 12-month rolling total operation and the appropriate emissions factors for the engines. If the NO_x emissions exceeds 200 tpy for the previous 12 months, the source shall submit a report of the emissions to the Executive Secretary within 30 days. Within 90 days the source shall submit to the Executive Secretary for approval a plan with proposed specifications for the installation, calibration, and maintenance of a continuous emissions monitoring system (CEMS) for NO_x. The CEM shall to be on line within 12 months following the approval of the plan .

8. Annual emissions for this source (the entire plant) are hereby established at 1.06 tons/yr for PM_{10}, 5.97 tons/yr for SO_2, 250 tons/yr for NO_x.

2.2.E Central Valley Water Reclamation Facility

1. The installations shall consist of only the following equipment:

   One 1135 Kw Engine-Generator Set (to generate 38% of power)
   Four 625 Kw Engine-Generator Sets (to generate 62% of power)

2. Central Valley Water Reclamation shall install new engine-generator sets with a clean burn configuration to achieve a reduction in NO_x emissions.

3. Emissions to the atmosphere from the new 1135 Kw engine-generator shall not exceed the following rates/concentrations:

   A. Carbon Monoxide

      1) 2.78 lbs/hr
      2) 2.0 grams/bhp-hr

   B. Nitrogen Oxides

      1) 1.39 lbs/hr
      2) 1.0 grams/bhp-hr
      3) 80% conversion

4. Compliance with the above NO_x, and CO emissions limitations shall be performed as follows:

   A. Two sampling ports for the engine exhaust shall be installed -one placed before the catalytic converter and one after in accordance with 40 CFR 60, Appendix A, Method 1.

   B. Monitor Oxygen content of the exhaust at the inlet to the catalytic converter with a continuous sensor or automatic air fuel ratio controller to maintain optimum catalyst performance. Inlet oxygen content shall be maintained in the range of 1,000 to 5,000 ppmv.

   C. Conduct a monthly evaluation of the catalyst degradation by measuring the appropriate contaminant concentration before and after the catalytic converter(s). The concentration shall be measured using a portable monitor specifically designed to measure the contaminant in the range required to demonstrate compliance or appropriate stain tube indicators. A hot air probe or equivalent shall be used to prevent errors in the results due to high stack temperatures.

D. The converter outlet concentration of CO shall not exceed 550 ppmv (2 gr/bhp-hr) while simultaneously maintaining a 80% conversion of NO_x. The calculation for NO_x conversion shall be make using the concentrations measured in accordance with paragraph C and as follows:

$$\frac{\text{Inlet concentration} - \text{Outlet concentration}}{\text{Inlet concentration}}$$

If the converter is unable to attain this emission limit, the converter catalyst shall be either cleaned or replaced.

E. Submit a quarterly report showing:

1) The raw monthly test data and any trends apparent in the data for the three contaminates

2) Calibrations of oxygen sensors and portable monitors

3) Occurrence and duration of downtime, start-up or malfunction in the operation of the engine or catalyst and corrective action taken

4) Exceedances in the limitations

5) Estimation of excess emissions

F. The quarterly report shall be submitted within 30 days from the last calendar day of the quarter

5. Emissions to the atmosphere from engines without catalytic converters shall not exceed the following rates/concentrations:

A. Carbon Monoxide

1) 17.6 lbs/hr per engine
2) 9.5 grams/bhp-hr

B. Nitrogen Oxides

1) 17.6 lbs/hr per engine
2) 9.5 grams/bhp-hr
3) 2,600 ppmv

6. Compliance with the above NO_x, and CO emissions limitations shall be performed as follows:

A. A sampling port for each engine exhaust shall be installed in accordance with 40 CFR 60, Appendix A, Method 1.

B. Conduct a monthly evaluation of the engine exhaust by measuring the appropriate contaminant concentration. The concentration shall be measured using a portable monitor specifically designed to measure the contaminant in the range required to demonstrate compliance or stain tube indicators. The concentration of each contaminant shall not be more than specified above. A hot air probe or equivalent shall be used to prevent errors in the results due to high stack temperatures.

C. Submit a quarterly report showing:

1) The raw monthly test data and any trends apparent in the data for the two contaminates for each engine

2) Calibrations of sensors and portable monitors as appropriate

3) Values at the time of tests for:
   * cylinder exhaust temperature
   * intake manifold pressure

4) Daily values for:
   * cylinder exhaust temperature
   * intake manifold pressure

5) Occurrence and duration of downtime, start-up or malfunction in the operation of the engine and corrective action taken

6) Calculate the emissions for the previous 12 month rolling total using the average measured concentration measured above and appropriate engine operating parameters

7) Exceedances in the limitations

8) Estimation of excess emissions

D. The quarterly report shall be submitted within 30 days from the last calendar day of the quarter.

E. Also, if sulfur content in digester gas is likely to be significant (such that an SO_2 emission limit, or a sulfur content limit in fuel, would be appropriate, as mentioned above), then an SO_2 stack test, or a test for sulfur content in digester gas, should also be required, if such a limit is set.

7. The owner/operator shall use only natural gas or digester gas as fuel in the engines. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

8. The following production limits hall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. A total of 13.35×10^3 MW*hr/yr for the three uncontrolled engines.

   B. 5.475 MW*hr/yr for the engine burning natural gas with the catalytic converter

   Compliance with these limits shall be in accordance with Section 2.1.D.

9. Annual emissions for this source (the entire plant) are hereby established at 0.67 tons/yr for PM_{10}, 3.96 tons/yr for SO_2, 203.7 tons/yr for NO_x.

2.2.F Centrex Corporation (Lone Star Industries, Inc.)

1. The installations shall consist of only the following equipment:

   A. Rotary Kiln #3
   B. Rotary Kiln #4
   C. Rotary Kiln #5
   D. Clinker Cooler #4
   E. Clinker Cooler #5
   F. Clinker Reclaim
   G. Finish Mill
   H. Rail Load-out System
   I. Kiln Dust Tank

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Rotary Kiln #3 Baghouse Vent

1.	PM_{10}	3.4	lbs/hr	0.017 grains/dscf	
2.	SO_2				
	One hour maximum	22	lb/hr	97	ppmdv
	Annual average	14	lb/hr	61	ppmdv
3.	NO_x				
	One hour	98	lb/hr	541	ppmdv
	24 hr rolling avg	70	lb/hr	386	ppmdv
	Annual average	55	lb/hr	304	ppmdv
4.	Kiln feed rate	27	Tons/hr		

   B. Rotary Kiln #4 Baghouse Vent

1.	PM_{10}	4.8	lbs/hr	0.017 grains/dscf	
2.	SO_2				
	One hour	28	lb/hr	88	ppmdv
	Annual average	16	lb/hr	50	ppmdv
3.	NO_x				
	One hour	126	lb/hr	498	ppmdv
	24 hr rolling avg	90	lb/hr	356	ppmdv
	Annual average	70	lb/hr	277	ppmdv
4.	Kiln feed rate	34	Tons/hr		

C. Rotary Kiln #5 Baghouse Vent

1.	PM_{10}	5.3	lbs/hr	0.017 grains/dscf	
2.	SO_2				
	One hour	28	lb/hr	88	ppmdv
	Annual average	16	lb/hr	50	ppmdv
3.	NO_x				
	One hour	126	lb/hr	498	ppmdv
	24 hr rolling avg	90	lb/hr	356	ppmdv
	Annual average	70	lb/hr	277	ppmdv
4.	Kiln feed rate	35	Tons/hr		

D. Clinker Cooler #4 Baghouse Vent

PM_{10} 2.6 lbs/hr 0.015 grains/dscf

E. Clinker Cooler #5 Baghouse Vent

PM_{10} 2.1 lbs/hr 0.015 grains/dscf

F. Clinker Reclaim Baghouse Vent

PM_{10} 3.6 lbs/hr 0.015 grains/dscf

G. Finish Mill #1 Baghouse Vent

PM_{10} 1.4 lbs/hr 0.016 grains/dscf

H. Finish Mill #2A Baghouse Vent

PM_{10} 0.5 lbs/hr 0.016 grains/dscf

I. Finish Mill #2B Baghouse Vent

PM_{10} 1.1 lbs/hr 0.016 grains/dscf

J. Rail Load-Out Baghouse Vent

PM_{10} 0.34 lbs/hr 0.016 grains/dscf

K. Kiln Dust Baghouse Vent

PM_{10} 0.27 lbs/hr 0.016 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see Section 2.1.A. for more details), and as directed by the Executive Secretary:

		Method	Retest every
A.	**Rotary Kiln #3 Baghouse Vent**		
1.	PM_{10}	201/201a	3 years
2.	SO_2	CEM UACR 4.6 Relative accuracy test	1 year
3.	NO_x	CEM UACR 4.6 Relative accuracy test	1 year
B.	**Rotary Kiln #4 Baghouse Vent**		
1.	PM_{10}	201/201a	1 year
2.	SO_2	CEM UACR 4.6 Relative accuracy test	1 year
3.	NO_x	CEM UACR 4.6 Relative accuracy test	1 year
C.	**Rotary Kiln #5 Baghouse Vent**		
1.	PM_{10}	201/201a	1 year
2.	SO_2	CEM UACR 4.6 Relative accuracy test	1 year
3.	NO_x	CEM UACR 4.6 Relative accuracy test	1 year
D.	**Clinker Cooler #4 Baghouse Vent**		
	PM_{10}	201/201a	3 years
E.	**Clinker Cooler #5 Baghouse Vent**		
	PM_{10}	201/201a	3 years
F.	**Clinker Reclaim Baghouse Vent**		
	PM_{10}	201/201a	3 years
G.	**Finish Mill #1 Baghouse Vent**		
	PM_{10}	201/201a	4 years

H. Finish Mill #2A Baghouse Vent

PM_{10}	201/201a	5 years

I. Finish Mill #2B Baghouse Vent

PM_{10}	201/201a	5 years

J. Rail Load-Out Baghouse Vent

PM_{10}	201/201a	Test if directed

K. Kiln Dust Baghouse Vent

PM_{10}	201/201a	Test if directed

The test methods used for PM_{10} shall be 40 CFR 60, Appendix A, and 40 CFR 51 Appendix M, Method 201/201a (see Paragraph 2.1.A.) and as directed by the Executive Secretary.

The clinker production/processing rate during compliance shall be no less than the rates indicated below:

Kiln #3	12.6 ton/hr
Kiln #4	16.2 ton/hr
Kiln #5	16.2 ton/hr
Clinker Coolers #3, #4, #5	45.0 ton/hr
Reclaim System	45.0 ton/hr
Finish Mill #1	21.6 ton/hr
Finish Mill #2	21.6 ton/hr
Finish Mill #3	21.6 ton/hr
Rail Load-out	67.5 ton/hr
Kiln Dust	4000 dscf/m

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. Rotary Kiln #3

1)	14	tons/hr of clinker produced
2)	110,376	tons/yr of clinker produced
3)	24	hours/day
4)	7884	hours/yr

B. Rotary Kiln #4

1)	18	tons/hr of clinker produced
2)	141,912	tons/yr of clinker produced
3)	24	hours/day
4)	7884	hours/yr

C. Rotary Kiln #5 Baghouse Vent

1)	18	tons/hr of clinker produced
2)	141,912	tons/yr of clinker produced
3)	24	hours/day
4)	7884	hours/yr

5. The exhaust gas streams from clinker coolers #3, #4 and #5 shall be routed to the two existing clinker cooler baghouses after passing through the heat exchanger.

6. Fugitive emissions from storage piles and others areas shall be water sprayed as dry conditions warrant to minimize emissions. Records of water treatment shall be kept for all periods when the installation is in operation. The records shall include the following items:

   A. Date
   B. Number of treatments made, dilution ratio, and quantity
   C. Rainfall received, if any, and approximate amount
   D. Time of day treatments were made

   Records of treatment shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

7. Annual emissions for this source (the entire plant) are hereby established at 111 tons/yr for PM_{10}, 200 tons/yr for SO_2, 762 tons/yr for NO_x. These amounts are only in effect if the installation subparts are capable of operating at the time this SIP is approved.

2.2.G Chevron U.S.A., Inc., Salt Lake Refinery, Davis County

1. The installations shall consist of the following equipment:

<u>Source</u> <u>Description</u>

A. Boilers and Furnaces:

1) Boilers #1 and #2
2) Boilers #3 and #4
3) Crude Furnaces F-1 and F-2
4) Crude Furnace F-2a
5) Crude Furnace F-3
6) HCC Furnace F-1
7) FCC Furnace F-21
8) FCC Furnace F-23
9) HDN Furnaces F-7110 and F-7130
10) Reformer Furnace F-1
11) Reformer Furnace F-2
12) Reformer Furnace F-3
13) Alkylation Furnace F-3617
14) Coker Furnace F-7001
15) Low Sulfur Diesel Plant Furnaces
16) Sulfur Plant Incinerator

B. Natural Gas Compressor Drivers:

1) HCC Compressor Drivers
2) FCC Compressor Drivers
3) Reformer Compressor Drivers

C. Catalytic Cracker Flue Gas:

1) HCC Plume Boiler
2) HCC Catalyst Disengager
3) FCC CO Boiler and Catalyst Regenerator

D. Flares:

1) Cracker Flare
2) Alkylation Flare
3) Coker Flare

E. Baghouse:

1) KOH Regenerator Lime Bin Baghouse

2. The following shall be the basis for SO_2 emissions limitations:

A. Emissions Limitation:

Chevron U.S.A., Inc., Salt Lake Refinery's maximum SO_2 emissions to the atmosphere shall not exceed 5.104 tons/day. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed 0.254 tons/day. The annual emission limitation for SO_2 from all sources shall not exceed 1,731 tons. Of this total, the annual SO_2 emissions from all sources included under the emissions cap shall not exceed 83.0 tons.

B. The following sources shall be included in the SO_2 Emissions Cap:

Boilers and Furnaces:

1) Boilers #1 and #2
2) Boilers #3 and #4
3) Crude Furnaces F-1 and F-2
4) Crude Furnace F-2a
5) Crude Furnace F-3
6) HCC Furnace F-1
7) FCC Furnace F-21
8) FCC Furnace F-23
9) HDN Furnaces F-7110 and F-7130
10) Reformer Furnace F-1
11) Reformer Furnace F-2
12) Reformer Furnace F-3
13) Alkylation Furnace F-3617
14) Coker Furnace F-7001
15) Low Sulfur Diesel Plant Furnaces

Natural Gas Compressor Drivers:

16) HCC Compressor Drivers
17) FCC Compressor Drivers
18) Reformer Compressor Drivers

C. SO_2 emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted. This shall be performed according to the following:

1) Emission Factors for the various fuels shall be as follows:

natural gas - 0.60 lb/mmscf

plant gas - the emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor which will measure the H_2S

content of the fuel gas in parts per million by volume (ppmv). The CEM shall be installed downstream of V-113 Fuel Gas Mix Drum. Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

(lb SO_2 / mmscf gas) = (24 hr avg. ppmv H_2S)/10^6 * (64 lb SO_2 / lb mole) * (10^6 scf / mmscf) / (379 scf / lb mole)

fuel oil - the emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

(lb SO_2 / kgal) = (density lb/gal) * (1000 gal/kgal) * (wt.% S)/100 * (64 g SO_2 / 32 g S)

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may only be combusted during periods of natural gas curtailment. The sulfur content of the fuel oil shall be tested if directed by the Executive Secretary.

2) Daily fuel gas consumption shall be quantified as:

meter number FR-409 (Furnaces and Boilers)

minus the readings from meters FRC-71 and FR-109B. These meters measure the gas feeds to the HCC Plume Boiler and to the FCC CO Boiler which are regulated as individual point sources (see number 2. D, below).

Daily fuel oil consumption shall be quantified as the sum of the individual consumptions measured by meters FR-2001, FR-2003, FR-2005, and FR-2007. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

Daily natural gas consumption shall be measured by meters FR-412 (HCC), FR-424 (FCC), and FR-66 (Reformer).

3) The equations used to determine emissions for the

boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Fuel Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Total 24-hour SO_2 emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above SO_2 emissions equations for fuel gas, fuel oil, and natural gas combustion. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt.% S, recorded for each day any fuel oil is burned), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

SO_2 emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for SO_2 at the following emission limits:

Point Source	lb/hr	tons/yr	ppmv
HCC Plume Boiler	66.33	290.4	316
HCC Catalyst Disengager	15.18	66.7	616
FCC CO Boiler and Catalyst Regenerator	145.3	636.5	850
Sulfur Plant Incinerator	*177.3	*654.0	*

*Actual emission limitations shall be established in accordance with UACR section 3.1.

E. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 2 D, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

F. The following sources shall not be regulated for SO_2 emissions, nor shall they be included in the emission limitation totals herein.

1) Cracker Flare
2) Alkylation Flare
3) Coker Flare
4) KOH Regenerator Lime Bin Baghouse

3. The following shall be the basis for NO_x emissions limitations:

A. Emissions Limitation:

Chevron U.S.A., Inc., Salt Lake Refinery's maximum NO_x emissions to the atmosphere shall not exceed 3.249 tons/day. Of this total, NO_x emissions from all sources included under the emissions cap shall not exceed 2.341 tons/day. The annual emission limitation for NO_x from all sources shall not exceed 1,022 tons. Of this total, the annual NO_x emissions from all sources included under the emissions cap shall not exceed 690.2 tons.

B. The following sources shall be included in the NO_x Emissions Cap:

Boilers and Furnaces:

1) Boilers #1 and #2
2) Boilers #3 and #4
3) Crude Furnaces F-1 and F-2
4) Crude Furnace F-2a
5) Crude Furnace F-3
6) HCC Furnace F-1
7) FCC Furnace F-21
8) FCC Furnace F-23
9) HDN Furnaces F-7110 and F-7130
10) Reformer Furnace F-1
11) Reformer Furnace F-2
12) Reformer Furnace F-3
13) Alkylation Furnace F-3617
14) Coker Furnace F-7001
15) Low Sulfur Diesel Plant Furnaces
16) Sulfur Plant Incinerator

Natural Gas Compressor Drivers:

17) HCC Compressor Drivers
18) FCC Compressor Drivers
19) Reformer Compressor Drivers

C. NO_x emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted. This shall be performed according to the following:

1) Boilers and Furnaces:

Emission Factors for the boilers and furnaces shall be as follows:

natural gas - 140 lb/mmscf
plant gas - 140 lb/mmscf
fuel oil - 120 lb/kgal

Daily fuel gas consumption by all boilers and furnaces shall be quantified as the sum of:

meter number FR-409 (Furnaces and Boilers) and meter number FR-479 (Sulfur Incinerator)(mscfh):

minus the readings from meters FRC-71 and FR-109B. These meters measure the gas feeds to the HCC Plume Boiler and to the FCC CO Boiler which are regulated as individual point sources (see number 3. D, below).

Daily fuel oil consumption shall be monitored by FR-2001, FR-2003, FR-2005, and FR-2007. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Fuel Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

2) Natural Gas Compressors:

Emission Factors for the natural gas compressor drivers shall be as follows:

natural gas - 3400 lb/mmscf

Daily natural gas consumption for the compressor drivers shall be measured as the sum of meters numbered FR-412 (HCC), FR-424 (FCC), and FR-66

(Reformer).

The equation used to determine emissions for the compressor drivers shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

3) Total 24-hour NO_x emissions for sources included in the emissions cap shall be calculated by adding the results of the above NO_x equations for fuel gas, fuel oil, and natural gas combustion. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

NO_x emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for NO_x at the following emission limits:

Point Source	lb/hr	tons/yr	ppmv
HCC Plume Boiler	13.06	57.2	86.7
HCC Catalyst Disengager	4.04	17.7	228
FCC CO Boiler and Catalyst Regenerator	58.56	256.5	477

E. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 3 D, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

F. The following sources shall not be regulated for NO_x emissions, nor shall they be included in the emission limitation totals herein.

1) Cracker Flare
2) Alkylation Flare
3) Coker Flare
4) KOH Regenerator Lime Bin Baghouse

4. The following shall be the basis for PM_{10} emissions limitations:

A. Emissions Limitation:

Chevron U.S.A., Inc., Salt Lake Refinery's maximum PM_{10} emissions to the atmosphere shall not exceed 0.479 tons/day. Of this total, PM_{10} emissions from all sources included under the emissions cap shall not exceed 0.044 tons/day. The annual emission limitation for PM_{10} from all sources shall not exceed 175 tons. Of this total, the annual PM_{10} emissions from all sources included under the emissions cap shall not exceed 16.3 tons.

B. The following sources shall be included in the PM_{10} emissions cap:

Boilers and Furnaces:

1) Boilers #1 and #2
2) Boilers #3 and #4
3) Crude Furnaces F-1 and F-2
4) Crude Furnace F-2a
5) Crude Furnace F-3
6) HCC Furnace F-1
7) FCC Furnace F-21
8) FCC Furnace F-23
9) HDN Furnaces F-7110 and F-7130
10) Reformer Furnace F-1
11) Reformer Furnace F-2
12) Reformer Furnace F-3
13) Alkylation Furnace F-3617
14) Coker Furnace F-7001
15) Low Sulfur Diesel Plant Furnaces
16) Sulfur Plant Incinerator

C. PM_{10} emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted. This shall be performed according to the following:

1) Emission Factors for the boilers and furnaces shall be as follows:

natural gas - 5 lb/mmscf

plant gas - 5 lb/mmscf

fuel oil - the PM_{10} emission factor for fuel oil combustion will be determined based on the H_2S content of the oil as follows:

PM_{10} (lb/kgal) = (10 * wt.% S) + 3

2) Daily fuel gas consumption by all boilers and furnaces shall be quantified as the sum of:

meter number FR-409 (Furnaces and Boilers) and meter number FR-479 (Sulfur Incinerator)(mscfh):

minus the readings from meters FRC-71 and FR-109B. These meters measure the gas feeds to the HCC Plume Boiler and to the FCC CO Boiler which are regulated as individual point sources (see number 4. D, below).

Daily fuel oil consumption shall be monitored by FR-2001, FR-2003, FR-2005, and FR-2007. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

3) The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Total 24-hour PM_{10} emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above PM_{10} emissions equations for fuel gas, fuel oil, and natural gas combustion. Results shall be tabulated every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt.% S), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. **Individual Point Source Limitation:**

PM_{10} emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for PM_{10} at the following emission limits:

Point Source	lb/hr	gr/dscf	tons/yr
HCC Plume Boiler	9.66	0.0520	42.3
HCC Catalyst Disengager	17.6	0.7455	77.1
FCC CO Boiler and			

Catalyst Regenerator	8.96	0.0662	39.2
Lime Bin Baghouse	0.11	0.020	0.48

E. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 4 D, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

F. The following sources shall not be regulated for PM_{10} emissions, nor shall they be included in the emission limitation totals herein.

1) HCC Compressor Drivers
2) FCC Compressor Drivers
3) Reformer Compressor Drivers
4) Cracker Flare
5) Alkylation Flare
6) Coker Flare

5. Stack Testing Requirements:

The following point sources have been required to comply with various emission rates and concentrations in the paragraphs preceding. The following is summary of the testing methods and frequencies appropriate to each point source. The provisions set forth in Appendix A 2.1.A of this document apply to the testing of these sources.

A) HCC Plume Boiler

	Limitations	Test Method	Frequency
SO_2	66.33 lb/hr 316 ppmv	6	If Directed
NO_x	13.06 lb/hr 86.7 ppmv	7	If Directed
PM_{10}	9.66 lb/hr .0520 gr/dscf	201/201a	Every 3 yrs.

B) HCC Catalyst Disengager

	Limitations	Test Method	Frequency
SO_2	15.18 lb/hr 616 ppmv	6	If Directed
NO_x	4.04 lb/hr 228 ppmv	7	If Directed
PM_{10}	17.6 lb/hr	201/201a	Every 3 yrs.

.7455 gr/dscf

C) FCC CO Boiler and Catalyst Regenerator

	Limitations	Test Method	Frequency
SO_2	145.3 lb/hr 850 ppmv	6	If Directed
NO_x	58.56 lb/hr 477 ppmv	7	If Directed
PM_{10}	8.96 lb/hr .0662 gr/dscf	201/201a	Every 3 yrs.

D) Sulfur Plant Incinerator

	Limitations	Test Method	Frequency
SO_2	*177.3 lb/hr * ppmv	CEM	Continuous

*Actual emission limitations shall be established in accordance with UACR section 3.1.

E) Lime Bin Baghouse

	Limitations	Test Method	Frequency
PM_{10}	0.11 lb/hr	201/201a	If Directed

6. Annual emissions for this source (the entire refinery) are hereby established at 175 tons/yr for PM_{10}, 2,578 tons/yr for SO_2 (which includes an additional 597.5 tons for routine sulfur plant down time and an estimated 250 tons for flare emissions), and 1,022 tons/yr for NO_x.

2.2.H Concrete Products Corporation - Walker Pit

1. The installations shall consist of only the following equipment located at the site:

   A. Three front-end loaders
   B. One haul truck
   C. One Dozer
   D. 30" x 42" Pioneer jaw crusher serial #V8326
   E. 54" Eljay standard cone crusher serial #278
   F. 54" Eljay fine cone crusher serial #524
   G. 5' x 16' Eljay screen serial #3460980
   H. 5' x 16' Cedar Rapids screen serial #1558
   I. 30" x 100' Radial stacker belt #65-128
   J. D-348 Cat generator #21-05
   K. 6' x 20' Eljay wash screen serial #825
   L. 30' x 100' Radial stacker belt #65-100
   M. H & B Asphalt Production Plant (each plant equipped with a baghouse)

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. North Standard 8000 Asphalt Plant Baghouse (NAPBH)

      1. PM_{10} 2.36 lbs/hr 0.024 grains/dscf

   B. South Standard 8000 Asphalt Plant Baghouse (SAPBH)

      1. PM_{10} 2.22 lbs/hr 0.024 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the plant exhaust stack emission point and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

	Method	Retest Every
Asphalt Plant Exhaust Stack		
PM_{10}	201/201a	3 year

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 340 tons/hr aggregate production
   B. 200,000 tons/yr aggregate production
   C. 300 tons/hr asphalt production per plant
   D. 100,000 tons/yr asphalt production per plant
   E. 8 hours/day plant and pit operation

F. 2080 hours/yr plant and pit operation

Aggregate production shall be determined by examination of sales receipts and hour of operation by an operations log.

5. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions to the indicated emissions limitations:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operating within the opacity limitation.

6. The owner/operator shall use only natural gas as a fuel in the asphalt plant. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

7. Annual emissions for this source (the entire plant) are hereby established at 34.7 tons/yr for PM_{10}, 1.3 tons/yr for SO_2, 17.4 tons/yr for NO_x.

2.2.I Concrete Products Corporation - Hobusch Pit

1. The installations shall consist of only the following equipment located at the site:

   A. 1 - Haul truck
   B. 2 - Front End loaders
   C. 10" x 36" Cedar Rapids jaw serial #15194
   D. 48" Telsmith cone crusher serial #6973
   E. 5' x 14' Eljay screen serial #831
   F. 4' x 2' Cedar Rapids wash screen serial #25565A
   G. 30" x 100' Radial stacker belt #65-79
   H. Rex central mix concrete batch plant complete with baghouses on the silos

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 250 tons/hr aggregate production
   B. 160,000 tons/yr aggregate production
   C. 200 cubic yards per hour concrete production
   D. 100,000 cubic yards per year concrete production
   E. 8 hours/day plant operation
   F. 2080 hours/year plant operation

3. The silos shall be pneumatically loaded with cement or flyash. The displaced air from the silos generated during filling shall be passed through a baghouse.

4. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. There shall be only 6 storage piles, and the total acreage of the 6 storage piles shall not exceed 15.0 acres.

5. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operating within the opacity limitation.

6. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 3.0% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the

Executive Secretary using the appropriate ASTM method.

7. Aggregate production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

8. Annual emissions for this source (the entire plant) are hereby established at 33.4 tons/yr for PM_{10}, 0.9 tons/yr for SO_2, 8.3 tons/yr for NO_x.

2.2.J Concrete Products Corporation - C.P.C. Plant 3

1. The installations shall consist of only the following equipment plus any equipment not capable of producing air contaminants:

   A. 6′ x 20′ Eljay wash screen serial #34H0179
   B. 24" x 129′ Radial stacker belt #54-04
   C. Clark/front-end loader
   D. Rex central mix concrete batch plant complete with baghouses on the silos

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 200 cubic yards of concrete per hour
   B. 85,000 cubic yards of concrete per year
   C. 8 hours/day of plant operation
   D. 2080 hours/yr of plant operation

3. The silos shall be pneumatically loaded with cement or flyash. The displaced air from the silos generated during filling shall be passed through a baghouse.

4. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. The total acreage of the 5 storage piles shall not exceed 5.0 acres.

5. The silt content of the product shall not exceed 3.0% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

6. Aggregate production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

7. Annual emissions for this source (the entire plant) are hereby established at 15.5 tons/yr for PM_{10}, 0.2 tons/yr for SO_2, 2.0 tons/yr for NO_x.

2.2.K Concrete Products Corporation - Whitehill Pit on Orchard Drive

1. The installations shall consist of only the following equipment capable of producing air contaminants located at the site:

   A. Three front-end loaders
   B. One Dozer
   C. One haul truck
   D. 22" x 36" Cedar Rapids jaw crusher serial #36464
   E. 48" Sysmans cone crusher serial #40088
   F. 54" Eljay cone crusher serial #404
   G. 4' x 12' Pioneer screen serial #412-4B-885
   H. 5' x 16' Eljay screen serial #34D0285
   I. 5' x 16' Eljay screen serial #1558
   J. Associated conveyor belts

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 325 tons/hr of aggregate production
   B. 475,000 tons/yr of aggregate production
   C. 8 hours/day of plant operation
   D. 2080 hours/yr of plant operation

   Aggregate production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

3. The haul road length shall not exceed 0.75 miles and the loader operations road shall not exceed 250 feet without prior approval in accordance with Section 3.1, UACR. The speed of vehicles on both the haul road and the loader operations road shall not exceed 10.0 miles per hour without prior approval in accordance with Section 3.1, UACR.

4. The open disturbed area shall not exceed 135.0 acres without prior approval from the Executive Secretary.

5. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. There shall be only 5 storage piles, and the total acreage of the 5 storage piles shall not exceed 10.0 acres.

6. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operating within the opacity limitation.

7. The moisture content of the material shall be maintained at a value of no less than 4.0% by weight. The silt content for the following products shall not exceed the following values without prior approval in accordance with Section 3.1, UACR:

A.	Base	9% by weight
B.	Sand	5% by weight
C.	Concrete aggregate	7% by weight
D.	1½" rock	7% by weight
E.	Class A chips	12% by weight

   The silt content shall be determined on a daily average. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

8. Annual emissions for this source (the entire plant) are hereby established at 48.0 tons/yr for PM_{10}, 0.9 tons/yr for SO_2, 9.8 tons/yr for NO_x.

2.2.L Crysen Refining, Inc., 2355 South 1000 West, Woods Cross, Davis County

1. The installation shall consist of the following equipment:

   A. Boilers and Furnaces

      1) H.D.S. Furnace [H-102]
      2) Reformer Furnace [H-101]
      3) Asphalt Blowing Furnace [F-701]
      4) Asphalt Furnace [F-601]
      5) Vacuum Furnace [F-501]
      6) No. 2 Crude Unit Furnace [-251]
      7) Preflash Furnace [F-231]
      8) Stabilizer Furnace [F-221]
      9) No. 1 Crude Unit Furnace [F-201]
      10) Steam Boiler No. 1 [B-1]
      11) Steam Boiler No. 2 [B-2]
      12) Steam Boiler No. 3 [B-3]

   B. Natural Gas Compressor Drivers (Reformer)

      13) 150 Hp Compressor [K-1]
      14) 150 Hp Compressor [K-2]
      15) 330 Hp Compressor [K-3]

   C. 16) The Refinery Flare

   D. 17) Sulfur Recovery Unit (SRU)

2. The following shall be the basis for SO_2 emissions limitations:

   A. Emissions Limitation:

      Crysen Refining, Inc., Salt Lake Refinery's maximum SO_2 emissions to the atmosphere shall not exceed 0.557 tons/day. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed 0.502 tons/day. The annual emission limitation for SO_2 from all sources shall not exceed 183 tons. Of this total, the annual SO_2 emissions from all sources included under the emissions cap shall not exceed 165.5 tons.

   B. The following sources shall be included in the SO_2 Emissions Cap.

      Boilers and Furnaces:

1) H.D.S. Furnace [H-102]
2) Reformer Furnace [H-101]
3) Asphalt Furnace [F-601]
4) Vacuum Furnace [F-501]
5) No. 2 Crude Unit Furnace [-251]
6) Preflash Furnace [F-231]
7) Stabilizer Furnace [F-221]
8) No. 1 Crude Unit Furnace [F-201]
9) Steam Boiler No. 1 [B-1]
10) Steam Boiler No. 2 [B-2]
11) Steam Boiler No. 3 [B-3]

Compressors:

12) 150 Hp Compressor [K-1]
13) 150 Hp Compressor [K-2]
14) 330 Hp Compressor [K-3]

C. SO_2 emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted. This shall be performed according to the following:

The total natural gas consumption at the plant is measured by meter FR-901. The gas stream splits downstream of this meter. The slipstream that is routed to the natural gas compressors is measured by meter FR-902. An emission factor of 0.60 lb/mmscf shall be applied to the quantity of natural gas metered by FR-902 for the 24-hour period to determine the daily emissions as:

Emission Factor (0.60 lb SO_2 / mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

The remaining portion of natural gas is blended with plant gas in the refinery fuel gas drum. The mixed gas is distributed to the boilers and furnaces throughout the plant. The flowrate of this gas stream is measured by meter FR-903. The emission factor to be used in conjunction with this gas stream is dependant on the H_2S content of the blended gas. The H_2S content shall be measured, in parts per million by volume (ppmv), by a continuous emissions monitor located downstream of the refinery fuel gas drum. Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

$(lb\ SO_2 / mmscf\ gas) = (24\ hr\ avg.\ ppmv\ H_2S)/10^6 * (64\ lb\ SO_2 / lb\ mole) * (10^6\ scf / mmscf) / (379\ scf / lb\ mole)$

The emissions associated with the combustion of this gas shall then be calculated as:

Emission Factor (lb SO_2 / mmscf) * Blended Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Fuel oil consumption shall be monitored with tank gauges. An emissions factor shall be calculated based on the sulfur content of the fuel oil (in weight percent), as determined by ASTM Method D-4294-89 or approved equivalent, and on the density of the fuel oil, as follows:

(lb SO_2 / kgal) = (density lb/gal) * (1000 gal/kgal) * (wt.% S)/100 * (64 g SO_2 / 32 g S)

Daily emissions shall then be calculated by applying this emission factor the amount of fuel oil consumed for the 24-hour period (kgal/24 hrs) as:

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

Fuel oil may only be combusted during periods of natural gas curtailment.

Total 24-hour SO_2 emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above SO_2 emissions equations for fuel gas, fuel oil, and natural gas combustion. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt.% S, recorded for each day any fuel oil is burned), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

SO_2 emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap

Sources shall be regulated individually for SO_2 at the following emission limits:

Point Source	lb/hr	tons/yr	gr/dscf
Asphalt Blowing Furnace (F-701)	4.60	17.5	0.10

SRU Tailgas Incinerator - limits shall be established in accordance with UACR 3.1

E. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 2 D, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

F. The following sources shall not be regulated for SO_2 emissions, nor shall they be included in the emission limitation totals herein.

1) The Refinery Flare

3. The following shall be the basis for NO_x emissions limitations:

A. Emissions Limitation:

Crysen Refining, Inc., Salt Lake Refinery's maximum NO_x emissions to the atmosphere shall not exceed 0.556 tons/day. Of this total, NO_x emissions from all sources included under the emissions cap shall not exceed 0.556 tons/day. The annual emission limitation for NO_x from all sources shall not exceed 156 tons. Of this total, the annual NO_x emissions from all sources included under the emissions cap shall not exceed 156 tons.

B. The following sources shall be included in the NO_x Emissions Cap:

Boilers and Furnaces:

1) H.D.S. Furnace [H-102]
2) Reformer Furnace [H-101]
3) Asphalt Blowing Furnace [F-701]
4) Asphalt Furnace [F-601]
5) Vacuum Furnace [F-501]
6) No. 2 Crude Unit Furnace [-251]
7) Preflash Furnace [F-231]

8) Stabilizer Furnace [F-221]
9) No. 1 Crude Unit Furnace [F-201]
10) Steam Boiler No. 1 [B-1]
11) Steam Boiler No. 2 [B-2]
12) Steam Boiler No. 3 [B-3]
13) 150 Hp Compressor [K-1]
14) 150 Hp Compressor [K-2]
15) 330 Hp Compressor [K-3]
16) SRU Tailgas Incinerator

C. NO_x emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted.

1) Boilers and Furnaces:

Emission Factors for the boilers and furnaces shall be as follows:

natural gas - 140 lb/mmscf
plant gas - 140 lb/mmscf
fuel oil - 120 lb/kgal

Daily gas consumption by all boilers and furnaces shall be measured by meter FR-903 located downstream of the refinery fuel gas drum. The gas that flows through this meter is actually a blend of plant gas and natural gas. Since the emission factors are considered to be the same for either gas (140 lb/mmscf), this factor will be applied to the metered quantity of blended gas.

Should future information reveal that there is a difference in the emission factors for natural gas and plant gas, then the respective quantities will need to be delineated as:

Natural Gas = (meter FR-901) - (meter FR-902)

Plant Gas = (meter FR-902) + (meter FR-903) - (meter FR901)

Daily fuel oil consumption shall be monitored with tank gauges. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

2) Natural Gas Compressors:

Emission Factors for the natural gas compressor drivers shall be as follows:

natural gas - 3400 lb/mmscf

Daily natural gas consumption for the compressor drivers shall be measured by meter FR-902.

The equation used to determine emissions for the compressor drivers will be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

3) Total 24-hour NO_x emissions for sources included in the emissions cap shall be calculated by adding the results of the above NO_x equations for fuel oil, natural gas, and (if necessary) plant gas combustion. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. The following sources shall not be regulated for NO_x emissions, nor shall they be included in the emission limitation totals herein.

1) The Refinery Flare

4. The following shall be the basis for the PM_{10} emissions limitations:

A. Emissions Limitations:

Crysen Refining, Inc., Salt Lake Refinery's maximum PM_{10} emissions to the atmosphere shall not exceed 0.0074 tons per day. Of this total, PM_{10} emissions from all sources included under the

emissions cap shall not exceed 0.0074 tons per day. The annual emission limitation for PM_{10} from all sources shall not exceed 2.70 tons. Of this total, the annual PM_{10} emissions from all sources included under the emissions cap shall not exceed 2.70 tons.

B. The following sources shall be included in the PM_{10} emissions cap:

1) H.D.S. Furnace [H-102]
2) Reformer Furnace [H-101]
3) Asphalt Blowing Furnace [F-701]
4) Asphalt Furnace [F-601]
5) Vacuum Furnace [F-501]
6) No. 2 Crude Unit Furnace [-251]
7) Preflash Furnace [F-231]
8) Stabilizer Furnace [F-221]
9) No. 1 Crude Unit Furnace [F-201]
10) Steam Boiler No. 1 [B-1]
11) Steam Boiler No. 2 [B-2]
12) Steam Boiler No. 3 [B-3]
13) SRU Tailgas Incinerator

C. PM_{10} emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relevant quantities of fuel combusted in each unit. This shall be performed according to the following:

1) Emission Factors for the combustion sources shall be as follows:

natural gas - 5 lb/mmscf

plant gas - 5 lb/mmscf

fuel oil - the PM_{10} emission factor for fuel oil combustion shall be determined based on the H_2S content of the fuel oil as:

PM_{10} (lb/kgal) = (10 * wt.% S) + 3

2) Daily plant gas consumption for the cap sources (all boilers and furnaces) shall be measured as follows:

Natural Gas = (meter FR-901) - (meter FR-902)

Plant Gas = (meter FR-902) + (meter FR-903) - (meter FR901)

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks which feed combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

3) The equations used to determine emissions shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Total 24-hour PM_{10} emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above PM_{10} emissions equations for plant gas, fuel oil, and natural gas combustion. Results shall be tabulated every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt.% S), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. The following sources shall not be regulated for PM_{10} emissions, nor shall they be included in the emission limitation totals herein.

1) 150 Hp Compressor [K-1]
2) 150 Hp Compressor [K-2]
3) 330 Hp Compressor [K-3]
4) The refinery flare

5. Stack Testing Requirements:

The following point sources have been required to comply with various emission rates and concentrations in the paragraphs preceding. The following is summary of the testing methods and frequencies appropriate to each point source. The provisions set forth in Appendix A 2.1.A of this document apply to the testing of these listed sources.

A. Asphalt Blowing Furnace

	Limitations	Test Method	Frequency
SO_2	4.60 lb/hr	6	If Directed

B. SRU Tailgas Incinerator

SO_2 shall be established in accordance with UACR 3.1	CEM	Continuous

6. Annual emissions for this facility are hereby established at 2.70 tons/yr for PM_{10}, 206 tons/yr for SO_2 (which includes an estimated 23 tons of emissions resulting from the sulfur plant being down for annual maintenance), and 156 tons/yr for NO_x.

2.2.M Engelhard - (Harshaw Filtrol)

1. The installations shall consist of the following equipment:

   A. Bulk alumina receiving, off-loading and storage facilities - vented to a New Micro-pulse air baghouse

   B. Two (2) Mixers - vented to Stack #2 through a cyclone and a Micro-pulse fabric filter

   C. Two (2) Extruders - not vented and not a source of air pollution

   D. Two (2) Slot Dryers - vented through Stack #3 with no emission controls

   E. One (1) Rotary Calciner - vented with no emission controls into the slot dryers for heat recovery, and/or through the slot calciner stack #7, and/or the wet scrubber (stack #6)

   F. Two (2) Impregnators - vented to Stack #2 through a cyclone and a Micro-pulse fabric filter

   G. One (1) Tray Dryer - vented through Stack #4 with no controls

   H. Screening & packaging operation - vented to Stack #5 through a Ducon Fabric Filter control device

   I. One (1) Cage Mill vented - vented to Stack #2 through a cyclone and a Micro-pulse fabric filter

   J. One (1) Slot Calciner - vented without control

   K. Catalyst Regeneration furnace and associated pollution control equipment (wet scrubber stack #6)

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Stack #2, Micro-pulse baghouse control:

      PM_{10} 0.390 lbs/hr 0.016 grains/dscf

   B. Stack #6, wet caustic scrubber control:

      1. PM_{10} 0.96 lb/hr 0.016 grains/dscf

2. SO_2 51 lb/hr max 31.5 ton (Averaged over 24 hr) 12-months rolling average

Sulfur emissions and reduction shall be determined by a mass balance method which shall be submitted by Engelhard and approved by the Executive Secretary. The method shall use an analysis for sulfur content of the catalyst before and after regeneration in conjunction with a 90% minimum removal efficiency of the SO_2 scrubber.

3. NO_x 113 lb/hr max 94.54 ton (averaged over 24 hr) 12-months rolling average

No_x emissions shall be determined by a mass balance method, process limitation or work practice methodology which shall be submitted by Engelhard prior to the promulgation of the SIP and approved by the Executive Secretary.

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

		Method	Retest every
A.	Stack #2, Micro-pulse baghouse control		
	PM_{10}	201/201a	Test if directed
B.	Stack #6, wet scrubber control		
1.	PM_{10}	201/201a	3 years
2.	SO_2	6	3 years

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. 2.6 ton/hr regenerated catalyst feed rate
B. 2,250 ton/yr regenerated catalyst
C. 1.5 ton/hr new catalyst materials feed rate
D. 3,500 tons/yr new catalyst
E. 7,884 hours per year

Production limitations shall be determined by examination of company production records which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation and production rates shall be determined by supervisor monitoring and maintaining an operations log.

5. Annual emissions for this source (the entire plant) are hereby established at 34.9 tons/yr for PM_{10}, 31.5 tons/yr for SO_2, 94.5 tons/yr for NO_x.

2.2.N Flying J Inc., - North Salt Lake

1. The installation shall consist of the following equipment:

Source	Fuel Consumed
A. Boilers and Furnaces:	
1) #1 Crude Heater	Gas **
2) Crude Preflash Heater	Gas
3) #2 Crude Heater	Gas
4) Vacuum Heater	Gas
5) Unifiner Startup Heater	Gas
6) Unifiner Heater	Gas
7) Reformer Heater	Gas
8) #1 Boiler	Gas
9) #2 Boiler	Gas
10) TCC Heater	Gas or Fuel Oil
11) Alky Heater	Gas or Fuel Oil
12) #7 C.O. Boiler	Gas or Fuel Oil
13) #6 Boiler	Gas or Fuel Oil
14) HDS Heater (future)	Gas or Fuel Oil
B. Catalytic Cracker:	
1) Plume Burner	Coke
2) TCC Separator Surge Drum	None
C. Natural Gas Compressors:	
1) Reformer Compressors	Gas
D. Flare:	
1) Flare Stack *	Gas
E. Sulfur Recovery Unit	
1) Tail Gas Incinerator	Gas

* Depending on the sulfur treatment technology selected, it is possible that a second small unit flare could be employed on the treatment plant.

** The designation "GAS" refers to either plant supplied fuel gas or utility supplied natural gas or a mixture of both.

2. The following shall be the basis for SO_2 emissions limitations:

A. Emissions Limitations:

Flying J, North Salt Lake Refinery's maximum SO_2 emissions to the atmosphere shall not exceed the following:

1) 2.904 tons per day between October 1 and March 31. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed (this amount less the contribution from the SRU tailgas incinerator) tons/day.

2) 3.779 tons per day between April 1 and September 30. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed (this amount less the contribution from the SRU tailgas incinerator) tons/day.

The annual emission limitation for SO_2 from all sources shall not exceed 824.8 tons. Of this total, the annual SO_2 emissions from all sources included under the emissions cap shall not exceed (this amount less the contribution from the SRU tailgas incinerator) tons.

B. The following sources shall be included in the SO_2 emissions cap:

	Source	Fuel
1)	#1 Crude Heater	Gas **
2)	Crude Preflash Heater	Gas
3)	#2 Crude Heater	Gas
4)	Vacuum Heater	Gas
5)	Unifiner Startup Heater	Gas
6)	Unifiner Heater	Gas
7)	Reformer Heater	Gas
8)	#1 Boiler	Gas
9)	#2 Boiler	Gas
10)	TCC Heater	Gas or Fuel Oil
11)	Alky Heater	Gas or Fuel Oil
12)	#7 C.O. Boiler	Gas or Fuel Oil
13)	#6 Boiler	Gas or Fuel Oil
14)	HDS Heater (future)	Gas or Fuel Oil
15)	Plume Burner	Coke
16)	Reformer Compressors	Gas

C. SO_2 emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted. This shall be performed according to the following:

1) Emission Factors for the various fuels shall be as follows:

natural gas - 0.60 lb/mmscf

plant gas - the emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor which will measure the H_2S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

$$(\text{lb } SO_2 \text{ / mmscf gas}) = (\text{24 hr avg. ppmv } H_2S)/10^6 * (\text{64 lb } SO_2 \text{ / lb mole}) * (10^6 \text{ scf / mmscf}) / (\text{379 scf / lb mole})$$

fuel oil - the emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

$$(\text{lb } SO_2 \text{ / kgal}) = (\text{density lb/gal}) * (\text{1000 gal/kgal}) * (\text{wt.\% S})/100 * (\text{64 g } SO_2 \text{ / 32 g S})$$

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment. The sulfur content of the fuel oil shall be tested if directed by the Executive Secretary.

2) Daily natural gas consumption shall be measured by the two meters that supply the refinery.

Daily plant gas consumption shall be measured by whatever meters are necessary to measure the flow of plant gas throughout the plant.

Daily fuel oil consumption shall be measured from the strapping conversion on the tank that feeds the combustion sources.

3) The equations used to determine emissions for the boilers and furnaces will be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) The daily SO_2 contribution from the Plume Burner shall be made by applying a scaling factor of known SO_2 emissions from past stack tests, to the charge rate of the TCC unit and the sulfur concentration of the feed. The TCC feed weight percent sulfur concentration shall be determined by the refinery lab monthly with one or more analyses. In addition, the gravity of the TCC feed shall be determined daily. When required by the Executive Secretary, a stack test for SO_2 shall be performed using appropriate EPA methods to verify or update the SO_2 scaling factor.

5) Total 24-hour SO_2 emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above SO_2 emissions equations for natural gas, plant gas, and fuel oil combustion to the estimate for the Plume Burner. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt.% S, recorded for each day any fuel oil is burned), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

SO_2 emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for SO_2 at the following emission limits:

Point Source	lb/hr	tons/yr	ppmv
Sulfur Recovery Unit	???	???	???

Actual limitations are to be established in accordance with UACR section 3.1.

E. Stack testing to determine hourly, daily, and annual compliance for the non-capped sources described in number 2 D, above, shall be performed as directed in number 5 below, and in accordance with sections 2.1.A and 2.1.M of this appendix.

F. The following sources shall not be regulated for SO_2 emissions, nor shall they be included in the emission limitation totals herein.

1) The TCC Seperator Surge Drum
2) The Plant Flare

3. The following shall be the basis for NO_x emissions limitations:

A. Emissions Limitations:

Flying J, North Salt Lake Refinery's maximum NO_x emissions to the atmosphere shall not exceed the following:

1) 0.923 tons per day between October 1 and March 31. Of this total, NO_x emissions from all sources included under the emissions cap shall not exceed 0.923 tons/day.

2) 1.041 tons per day between April 1 and September 30. Of this total, NO_x emissions from all sources included under the emissions cap shall not exceed 1.041 tons/day.

The annual emission limitation for NO_x from all sources shall not exceed 278.7 tons. Of this total, the annual NO_x emissions from all sources included under the emissions cap shall not exceed 278.7 tons.

B. The following sources shall be included in the NO_x emissions cap:

Source	Fuel
1) #1 Crude Heater	Gas **
2) Crude Preflash Heater	Gas
3) #2 Crude Heater	Gas
4) Vacuum Heater	Gas
5) Unifiner Startup Heater	Gas
6) Unifiner Heater	Gas
7) Reformer Heater	Gas

8)	#1 Boiler	Gas
9)	#2 Boiler	Gas
10)	TCC Heater	Gas or Fuel Oil
11)	Alky Heater	Gas or Fuel Oil
12)	#7 C.O. Boiler	Gas or Fuel Oil
13)	#6 Boiler	Gas or Fuel Oil
14)	HDS Heater (future)	Gas or Fuel Oil
15)	Plume Burner	Coke
16)	Reformer Compressors	Gas
17)	SRU Tailgas Incinerator	Gas

C. NO_x emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted.

1) Boilers and Furnaces:

Emission Factors for the boilers and furnaces shall be as follows:

natural gas - 140 lb/mmscf
plant gas - 140 lb/mmscf
fuel oil - 120 lb/kgal

Daily gas consumption by all boilers and furnaces shall be measured by whatever meters are necessary to delineate the flow of gas to the indicated sources.

Since the emission factors are considered to be the same for either gas (140 lb/mmscf), this factor will be applied to the metered quantity of blended gas. Should future information reveal that there is a difference in the emission factors for natural gas and plant gas, then the respective quantities will need to be delineated.

Daily fuel oil consumption shall be monitored with tank gages. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

2) Reformer Compressors:

The Emission Factors for the compressor drivers shall be as follows:

natural gas - 3400 lb/mmscf
plant gas - 3400 lb/mmscf

Daily gas consumption for the compressor drivers shall be measured by whatever meters are necessary to delineate the flow of gas to the compressors.

The equation used to determine emissions for the compressor drivers shall be as follows:

Emission Factor (lb/mmscf) * Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

3) The daily NO_x contribution from the Plume Burner shall be determined by applying a scaling factor of known NO_x emissions to the unit combustion air flow rate. The combustion air flow rate is the process control for regulating coke buildup on the catalyst. The volumetric measurement shall be based upon operator readings for combustion air fan flow. The NO_x emission factor shall be initially established in accordance with Section 3.2.5 UACR, and updated when required by the Executive Secretary using appropriate EPA methods.

4) Total 24-hour NO_x emissions for sources included in the emissions cap shall be calculated by adding the results of the above NO_x equations for fuel oil, natural gas, and (if necessary) plant gas combustion to the estimate for the Plume Burner. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. The following sources shall not be regulated for NO_x emissions, nor shall they be included in the emission limitation totals herein.

1) The TCC Seperator Surge Drum

2) The Refinery Flare

4. The following shall be the basis for PM_{10} emissions limitations:

A. Emissions Limitations:

Flying J, North Salt Lake Refinery's maximum PM_{10} emissions to the atmosphere shall not exceed the following:

1) 0.122 tons per day between October 1 and March 31. Of this total, PM_{10} emissions from all sources included under the emissions cap shall not exceed .082 tons/day.

2) 0.112 tons per day between April 1 and September 30. Of this total, PM_{10} emissions from all sources included under the emissions cap shall not exceed .072 tons/day.

The annual emission limitation for PM_{10} from all sources shall not exceed 22.0 tons. Of this total, the annual PM_{10} emissions from all sources included under the emissions cap shall not exceed 7.30 tons.

B. The following sources shall be included in the PM_{10} emissions cap:

	<u>Source</u>	<u>Fuel</u>
1)	#1 Crude Heater	Gas **
2)	Crude Preflash Heater	Gas
3)	#2 Crude Heater	Gas
4)	Vacuum Heater	Gas
5)	Unifiner Startup Heater	Gas
6)	Unifiner Heater	Gas
7)	Reformer Heater	Gas
8)	#1 Boiler	Gas
9)	#2 Boiler	Gas
10)	TCC Heater	Gas or Fuel Oil
11)	Alky Heater	Gas or Fuel Oil
12)	#7 C.O. Boiler	Gas or Fuel Oil
13)	#6 Boiler	Gas or Fuel Oil
14)	HDS Heater (future)	Gas or Fuel Oil
15)	Plume Burner	Coke
16)	SRU Tailgas Incinerator	Gas

C. PM_{10} emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relevant quantities of fuel combusted in each unit. This shall be performed according to the following:

1) Emission Factors for the combustion sources shall be as follows:

natural gas - 5 lb/mmscf

plant gas - 5 lb/mmscf

fuel oil - the PM_{10} emission factor for fuel oil combustion shall be determined based on the H_2S content of the oil as follows:

PM_{10} (lb/kgal) = (10 • wt.% S) + 3

2) Daily natural gas consumption for the cap sources (all boilers and furnaces) shall be measured by whatever meters are necessary to delineate the flow of gas to the indicated sources.

Daily plant gas consumption for the cap sources (all boilers and furnaces) shall be measured by whatever meters are necessary to delineate the flow of plant gas to the indicated sources.

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

3) The equations used to determine emissions shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) The daily primary PM_{10} contribution from the Plume Burner shall be determined by applying an emission factor based upon the unit combustion air flow rate. The combustion air flow rate is the process control for regulating coke buildup on the catalyst. The volumetric measurement shall be based upon operator readings for combustion air fan flow. The emission factor shall initially be established in accordance with

Section 3.2.5 UACR, and updated when required by the Executive Secretary using appropriate EPA methods.

5) Total 24-hour PM_{10} emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above PM_{10} emissions equations for plant gas, fuel oil, and natural gas combustion to the estimate for the Plume Burner. Results shall be tabulated every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt.% S), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

PM_{10} emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for PM_{10} at the following emission limits:

Point Source	lb/hr	tons/yr	gr/dscf
1) TCC Separator Surge Drum	4.18	14.7	0.12

E. The following sources shall not be regulated for PM_{10} emissions, nor shall they be included in the emission limitation totals herein.

1) The Reformer Compressors
2) The Plant Flare

5. Stack Testing Requirements:

The following point sources have been required to comply with various emission rates and concentrations in the paragraphs preceding. The following is summary of the testing methods and frequencies appropriate to each point source. The provisions set forth in Appendix A 2.1.A of this document apply to the testing of these listed sources.

A. The Plume Burner

	Limitations	Test Method	Frequency
SO_2	*NA	6	2 yrs.

*Although there is no specified limitation, the test results are to be used in conjunction with a scaling factor to be applied to this source on a daily basis.

B. The TCC Seperator Surge Drum

	Limitations	Test Method	Frequency
PM_{10}	4.18 lb/hr 0.12 gr/dscf	201/201a	If Directed

C. Sulfur Removal Unit (Tail Gas):

	Limitations	Test Method	Frequency
SO_2	???? lb/hr ??? ppmv	CEM	Continuous

Actual limitations are to be established in accordance with UACR section 3.1.

6. Annual emissions for this source (the entire plant) are hereby established at 22.0 tons per year for PM_{10}, 864.6 tons per year (which includes 39.8 tons of emissions resulting from the sulfur plant being down for annual maintenance) for SO_2, and 278.7 tons per year for NO_x. Note that these totals include 0.06, 4.0, and 6.7 tons per year of PM_{10}, SO_2, and NO_x respectively as preliminary estimates for emissions resulting from a De-Waxing Unit, the plans for which are being reviewed at the time of this writing.

2.2.0 Geneva Rock Products, Inc - (350 West 3900 South, Salt Lake City)

1. The installations shall consist of only the following equipment:

   A. Two Concrete Batch Plants
   B. Cement/Flyash Silos
   C. Diesel Loaders and Truck

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A.	400	Cubic Yards/hr
B.	167,500	Cubic Yards/yr
C.	14	hours/day
D.	3,120	hours/yr

   Concrete production be determined by plant sales records.

3. The silos shall be pneumatically loaded with cement or flyash. The displaced air from the silos generated during filling shall be passed through a baghouse.

4. The mix truck haul road shall be paved and shall be cleaned by a street vacuum equipped with a baghouse or by water flooding as necessary to minimize fugitive dust.

5. The disturbed area shall not exceed 10 acres without prior approval from the Executive Secretary.

6. Annual emissions for this source (the entire plant) are hereby established at 4.53 tons/yr for PM_{10}, 0.45 tons/yr for SO_2, 5.28 tons/yr for NO_x.

2.2.P Geneva Rock Products, Inc - (Point of the Mountain Pit)

1. The approved installations shall consist of only the following equipment:

A. In the Hansen Pit

1. The L-4 Crushing Plant:

Triple Deck Eljay Screen (#34L1079)
45 inch Eljay Cone Crusher (#22G0690)
Eljay 6' X 16' Wash Screen (#34J0385)
Associated Conveyors
Two (2) Front End Loaders

2. The G-4 Cement Batch Plant:

Ross model 135 Batch Plant (#135-32)
Ross model V200 600 CFM Bin Vent (cement silo)
Todd model 36-SK 600 CFM Bin Vent (flyash silo)
One Front End Loader

B. In the North Hansen Pit

1. The L-3 Portable Crushing Plant:

Cedarapids Jaw Crusher/Screen Deck (#21447)
Eljay Cone Crusher/Screen Deck (#42A0278)
Associated Conveyors

One bulldozer
Two front End Loaders
One generator

2. The L-5 Portable Crushing Plant:

Cedarapids Screen/Jaw/Rolls unit (#13385)
Eljay 4' X 12' Wet Screen Deck
Associated Conveyors
Two Front End Loaders
Two Generators

3. Additional Equipment:

45 inch Eljay Cone Crusher (41J0581)
Eljay 5' X 16' Screen Deck (#34D1481)
Universal Rolls (#207X46)
One Generator
Cedarapids Jaw Crusher (#21480)
One Bulldozer
One Loader

4. The F-1 Hot Plant:

Todd Model 36-DK 600 CFM Bin Vent (Lime Silo)
CMI Oil Fired Drum Mix Asphalt Plant with Venturi Scrubber (#UVM-1700)
One Front End Loader

C. In the Mount Jordan Pit

1. The L-1 Crushing Plant:

Eljay 5' X 16' Screen Deck (#34L0277)
Eljay 45" Cone Crusher (#533)
Eljay 5' X 16' Wet Screen Deck (#34J0783)
Eljay 5' X 16' Wet Screen Deck (#34E0984)
Associated Conveyors
Two Front End Loader

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

A. The CMI Asphalt Plant

1.	PM_{10}	3.34 lbs/hr	0.024 grains/dscf (Virgin)
2.	PM_{10}	3.90 lbs/hr	0.028 grains/dscf (Recycle)
3.	SO_2	18.72 lbs/hr	118 ppmdv

Stack testing to show compliance with the above emissions limits shall be performed in accordance with paragraph 2.1.A and every three years thereafter.

3. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

A. All crushers
B. All screens
C. All conveyor transfer points

The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation of 10%.

4. Water shall be added to the mined material (to be bulldozed) such that before the material is moved, its moisture content, as determined by ASTM Method D-2216 on the -40 mesh portion of the sample, is greater than 4.0% by weight. This moisture content shall be maintained

throughout subsequent crushing, screening and conveying circuits. The silt content of the product shall not exceed 15% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

5. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. For the Asphalt Plant:

      1. 285 tons/hr
      2. 250,000 tons/yr

   B. For the Concrete Batch Plant:

      1. 100 cubic yards/hr
      2. 200,000 cubic yards/yr

   C. For the Aggregate Pits:

      1. 900 tons/hr of crushing/screening production
      2. 1,000,000 tons of mined material per year
      3. 2,000 hours of operation per unit per year

   Asphalt, concrete and pit production shall be determined through the use of weigh scales and recording of the weights. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

6. The batcher unit on the Ross Plant shall be enclosed in a building as proposed in the notice of intent dated September 4, 1984, and the loading process from the discharge hopper into the mixer trucks shall be controlled by an adjustable boot.

7. The cement and flyash silos shall be pneumatically loaded. The displaced air from the silos generated during filling shall be passed through a baghouse. The flow rate through the baghouse shall not exceed 600 ACFM. The baghouse flow rate shall be measured at the request of the Executive Secretary. The method shall be 40 CFR 60, Appendix A, Method 2.

8. For the asphalt plant, the following operating parameters shall be maintained within the indicated ranges:

   A. Pressure drop across the venturi scrubber - 15" nominal, 13" w.g. minimum

B. Scrubber liquid flow rate - 300 gallons per minute nominal, 275 gpm minimum 225 gpm

They shall be monitored with equipment located such that an inspector can at any time safely read the output. The readings shall be accurate to within the following ranges:

A. Plus or minus 1.0 inch w.c.
B. Plus or minus 15 gpm

All instruments shall be calibrated against a primary standard at least once every 90 days. The primary standard shall be specified by the Executive Secretary.

9. Under no circumstances shall the percent by weight of recycle asphalt exceed 50%.

10. The owner/operator shall use only Number 2 fuel oil or better as fuel or other fuel that can demonstrate sulfur content of less than 0.45% (less then 0.05% after December 1993) by weight. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of any fuel oil burned shall not exceed 0.45% by weight as determined by ASTM Method D-4294-89 or, as appropriate, the sulfur content of any fuel oil burned shall not exceed 0.25 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall be determined by examination of vendor sales receipts which shall be maintained for two years. These records shall be made available to the Executive Secretary upon request.

11. The open disturbed area shall not exceed 150 acres without prior approval from the Executive Secretary.

12. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. The total acreage of the storage piles shall not exceed 75 acres.

13. All installations and facilities authorized by this subsection shall be adequately and properly maintained.

14. Annual emissions for this source (the entire plant) are hereby established at 81.0 tons/yr for PM_{10}, 9.64 tons/yr for SO_2, 21.4 tons/yr for NO_x.

2.2.Q Harper Sand & Gravel Inc., - (Pit #1)

1. The installations shall consist of only the following equipment capable of producing air contaminants located at the site:

   A. El Jay cone crusher 45" SN 22J 0878
   B. 5' x 16' triple deck screen (wet) SN 34J 0978
   C. One 30" x 26' conveyor belt
   D. One 30" x 45' conveyor belt
   E. One 42" x 27' conveyor belt
   F. Eagle sand screw 30" x 26'
   G. Three front end loaders
   H. One haul truck

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 280 tons/hr of aggregate
   B. 400,000 tons/yr of aggregate
   C. 12 hours/day
   D. 3744 hours/yr

3. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

4. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 7.0% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

5. Annual emissions for this source (the entire plant) are hereby established at 7.8 tons/yr for PM_{10}, 1.9 tons/yr for SO_2, 18.4 tons/yr for NO_x.

2.2.R Harper Sand and Gravel, Inc - Pit #10

1. The installations shall consist of only the following equipment capable of producing air contaminants located at the site:

   A. Telesmith cone crusher SN 8909 485
   B. D 343 Cat Generator SN 62B 16385
   C. One 30" x 35" belt feeder
   D. One Coleman 40" x 22' conveyor belt SN 22-40-24-59
   E. One 30" x 100' radial stacker belt
   F. Three front end loaders
   G. One bulldozer

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 280 tons/hr of aggregate
   B. 400,000 tons/yr of aggregate
   C. 12 hours/day
   D. 3744 hours/yr

   Aggregate production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

3. The open disturbed area shall not exceed 50.0 acres without prior approval from the Executive Secretary.

4. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. The total acreage of the storage piles shall not exceed 2.0 acres.

5. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

6. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 10.0% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be

tested if directed by the Executive Secretary using the appropriate ASTM method.

7. Annual emissions for this source (the entire plant) are hereby established at 16.3 tons/yr for PM_{10}, 1.6 tons/yr for SO_2, 17.9 tons/yr for NO_x.

2.2.S Hercules Aerospace Company - Plant #1

1. The buildings listed below have been evaluated and determined that they have sufficient potential emissions to be emitted from the buildings, building vents or stacks to require regulation:

Building - 18	NIROP natural gas fired boilers
Burning Grounds - 32A	Open burning of waste propellant and contaminated waste.
Building - 2334	Paint booth in finish area
Building - 8501	Powerhouse for plant steam production
Building - CD2A/2C	HMX Grinder Building
Bacchus West	Special Conditions

2. Hercules shall use natural gas as primary fuel in all fuel burning furnaces, ovens and boilers. Number 2 fuel oil or better shall be used only as a backup fuel to be used during natural gas curtailments and for maintenance firing. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. Fuel consumption shall be determined by gas meter readings and oil receiving and inventory records.

   The #2 fuel oil may be used only during periods of natural gas curtailment, and for maintenance firings. Maintenance firings shall not exceed 1% of the annual plant BTU requirement. Records of fuel oil use shall be kept which shows the date the oil was fired, the duration in hours the oil was fired, the amount of fuel oil consumed and the reason for each firing.

3. The total natural gas consumption limit for all facilities shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   1080 Million cubic feet per year

   Natural gas consumption shall be determined by Mountain Fuel Company's gas meter readings. The records shall be kept on a monthly basis.

4. The owner/operator shall use only Number 2 fuel oil or better as fuel or other fuel that can demonstrate sulfur content of less than 0.45% by weight. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of

any fuel oil burned shall not exceed 0.45% by weight as determined by ASTM Method D-4294-89 or, as appropriate, the sulfur content of any fuel oil burned shall not exceed 0.25 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall be determined by examination of vendor sales receipts which shall be maintained for two years. These records shall be made available to the Executive Secretary upon request.

5. All paint booths shall be equipped with particulate filters to control emissions.

6. All plant roads and parking lots shall be paved, with the exception of some power line maintenance roads, and shall be cleaned by a street vacuum equipped with a baghouse or by water flooding as necessary to minimize fugitive dust.

7. Annual emissions for this source Plant #1 (plant #1, NIROP and Bacchus West) are hereby established at 241.3 tons/yr for PM_{10}, 1.4 tons/yr for SO_2, and 142.0 tons/yr for NO_x.

Building - CD2A/2C - HMX Grinder Building

1. Each building/installation shall consist of the following equipment capable of PM_{10} emissions:

   A. HMX air jet collision grinders
   B. Jetomizer baghouse (2)
   C. 1st secondary disposable filter rated at 99.5%
   D. 2nd secondary disposable filter rated at 99.7%

2. Visible emissions from any point or fugitive emission source associated with these installations/buildings or control facilities shall not exceed 0% opacity.

3. The following production and operating limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 50,000 lb HMX ground/month
   B. 500,000 lb HMX ground/year

   Production shall be determined by examination of company operations records. Records shall be kept on a monthly basis.

Building - 18 - NIROP Natural Gas Boiler Stacks 1, 2 & 3

1. The installations shall consist of the following equipment

capable of PM_{10} emissions:

A. Bld 18-Stack 1, - 29.1 MMBTUH natural gas fired boiler
B. Bld 18-Stack 2, - 29.1 MMBTUH natural gas fired boiler
C. Bld 18-Stack 3, - 29.1 MMBTUH natural gas fired boiler

Building - 32A - Burning Grounds

1. The installations shall consist of the following equipment capable of PM_{10} emissions:

   A. Three burning cages
   B. 16 open burn pans

2. The following quantities of waste to be incinerated shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 4500 lb/day waste propellant
   B. 822 tons/yr total waste propellant
   C. 1,114 tons/yr total waste burned

   The records shall be kept on a daily basis.

3. Open burning of waste propellant and contaminated wastes shall not be done during days when a Salt Lake County "No Burn" order is in effect for wood stoves, except that the most unstable (i.e. nitroglycerin) wastes shall be allowed to be burned. These special burns of unstable wastes shall not exceed 400 lb/day.

   The backlog of wastes not burned during the "No Burn" days for wood stoves shall be destroyed at up to a total of 6,000 lb/day on the days following the burning restrictions.

4. Hercules shall submit a notice of intent to construct a waste propellant incinerator by December 31, 1992. The tentative date for completion of the installation of the incinerator shall be 24 months after approval by both the Bureau of Air Quality and the Bureau of Solid and Hazardous Waste.

5. Hercules shall submit an annual progress report on the development of a waste propellant incinerator to be submitted within 30 days of the end of each calendar year.

Building 2334 - Finishing Building 2

1. The installations shall consist of only a paint booth with dry type disposable paint particulate filters.

Building - 8501 - Plant #1 Boilers

1. The installations shall consist of the following equipment capable of PM_{10} emissions:

   A. Nebraska natural gas fired boiler - rated @ 25 MMBTUH
   B. Murray natural gas fired boiler - rated at 25 MMBTUH
   C. Keeler replacement natural gas fired boiler - rated at < 50 MMBTW - Notice of intent, with details, shall be submitted and processed prior to construction in accordance with Section 3.1, UACR.

      A schedule for installation of the replacement natural gas fired boiler shall be submitted by April 1, 1991. The amount of natural gas anticipated to be used in the replacement boiler has been included in this approval order as well as the potential emissions based on AP 42 1.4 emissions factors.

   D. Keeler coal-fired boiler - The boiler shall be operated until December 31, 1992 by which time the boiler shall be disabled or removed. Visible emissions from the exhaust stack shall not exceed 20% opacity.

Bacchus West Buildings

1. The aluminum premix systems shall be designed to properly seal as proposed to prevent escape of fugitive particulate emissions. The operation shall be inclosed in building 2429

2. The weigh hoppers and transport bins in the 1800 gallon mix building shall be properly sealed as proposed to prevent escape of fugitive particulate emissions.

3. Paint booths with dry type paint arrestor particulate filters.

2.2.T Hercules Aerospace Company - Plant #3 - Graphite Fiber Production

The buildings listed below have been evaluated and determined to have sufficient potential PM_{10} emissions emitted from the buildings, building vents or stacks to require regulation.

Building - 2344 - Graphite fiber production, Lines #1, #2, & #3

Building - 2436 - Graphite fiber production, Lines #4 & #5

Building - 2440 - 3D Carbon-carbon structures

Building - 2478 - Solvent coating and resin prep and handling

Building - 2479 - Graphite fiber production, Lines #6 & #7

Building - 8162 - R & D facility with an incinerator

General Conditions for Plant #3,

The following regulations shall apply to any point or fugitive source at Plant #3:

1. Visible emissions from any point or fugitive emission source associated with the installation or control facilities shall not exceed 10% opacity. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

2. All plant roads and parking lots shall be paved, with the exception of some power line maintenance roads, and shall be cleaned by a street vacuum equipped with a baghouse or by water flooding as necessary to minimize fugitive dust.

3. The following consumption/production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 175 million scf of natural gas per year
   B. 10.8 million lb of carbon fibers from the fiberlines per year

   Natural gas consumption shall be determined by gas billing records for the plant and graphite products production shall be determined by plant production records.

4. Hercules Plant #3 shall use natural gas as primary fuel in all fuel burning furnaces, ovens, incinerators, and boilers. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

5. The incinerator exhaust stacks need not be constructed to accommodate testing. However, if the Executive Secretary determines a stack test is necessary, whatever modifications needed to meet 40 CFR 60, Appendix A, Method 1 and to provide OSHA approvable access to the test location shall be retrofitted to the emission point.

6. All emergency generators shall be used only when the normal power sources have failed and created emergency conditions, except for normal maintenance start-up procedures. The total use rate per generator set shall not exceed 65 hours per year unless it is reported under Section 4.7, UACR (unavoidable breakdown).

7. Annual emissions for this source (the entire plant #3) are hereby established at 76.8 tons/yr for PM_{10}, 0.1 ton/yr for SO_2 and 98.9 tons/yr for NO_x

Building - 2344 - Graphite Fiber Production, Lines #1, #2, & #3

1. The installations shall consist of only the following equipment:

   A. Graphite Fiber Lines #1, #2, and #3 with electrically heated oxidation ovens, low temperature carbonization furnaces, high temperature carbonization furnaces, fiber sizing operations, and spooling operations

   B. Three (3) John Zink or equivalent system, natural gas fired fume incinerators as described in the Material List submitted June 8, 1979, to control emissions from the low temperature carbonization furnaces

   C. Three (3) standby emergency generators:

      1 @ 250 kw, diesel fueled
      1 @ 125 kw, diesel fueled
      1 @ 45 kw, natural gas fueled

2. The fume incinerators shall be operated and maintained

with a minimum temperature of 1400°F. The incinerator temperature shall be monitored with temperature sensing equipment which shall be capable of continuous measurement and readout of the combustion temperature with the readout located such that an inspector/operator can at any time safely read the output. The measurement shall be accurate as specified below. The measurement need not be continuously recorded.

All instruments shall be calibrated against a primary standard at least once every 180 days. The calibration procedure shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 4.3.

3. The incinerator shall be designed with a minimum residence time of 0.5 sec at maximum flow rate.

4. All effluent stack/vents shall have wire mesh filters to control broken carbon filaments, except those stacks vented to the fume incinerators, high temperature furnace outlet stacks on Fiberlines #2 & #3, end chamber fans on the oxidation ovens and surface treatment stacks.

Building - 2436 - Graphite Fiber Production, Lines #4 & #5

1. The installations shall consist of the following equipment capable of PM_{10} emissions:

   A. Graphite fiber line #4 with electrically heated oxidation ovens, low temperature carbonization furnace, and high temperature carbonization furnace. The low temperature carbonization furnace emissions shall be controlled by a fume incinerator. The high temperature carbonization furnace shall be retrofitted with a burner box at the furnace entrance equipped with pilot lights to insure that combustion takes place.

   B. Graphite fiber line #5 with natural gas fired oxidation ovens, electrically heated-low temperature carbonization furnace, and high temperature carbonization furnace. The low temperature carbonization furnace emissions shall be controlled by a fume incinerator. The high temperature carbonization furnace shall be retrofitted with a burner box at the furnace entrance equipped with pilot lights to insure that combustion takes place.

   C. Two (2) John Zink, natural gas fired fume incinerators as described in the notice of intent dated November 19, 1980.

D. One 6.3 MMBTU/Hr natural gas fired standby boiler.

E. Two Diesel fired emergency generators as follows:

1. 1 - rated at 180 kw
2. 1 - rated at 200 kw

2. The fume incinerators shall be operated and maintained with a minimum temperature of 1400°F. The incinerator temperature shall be monitored with temperature sensing equipment which shall be capable of continuous measurement and readout of the combustion temperature with the readout located such that an inspector/operator can at any time safely read the output. The measurement shall be accurate as specified below. The measurement need not be continuously recorded.

All instruments shall be calibrated against a primary standard at least once every 180 days. The calibration procedure shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 4.3.

3. The incinerator shall be designed with a minimum residence time of 0.5 seconds at maximum flow rate.

4. All effluent stack/vents for process emissions shall have wire mesh filters to control broken carbon filaments, except those stacks vented to the fume incinerators.

Building - 2440 - 3D Carbon-Carbon Structures

1. The approved installations shall consist of the following equipment capable of PM_{10} emissions:

A. Exhaust fan with fiber collection system
B. Emergency generator, 100 kw - natural gas fired
C. Incinerator, 1 MMBTU/Hr minimum rate
D. Sanding area with fiber collection system

2. The incinerator (1.C) for the destruction of polynuclear aeromatics and other polynuclear aeromatics and hydrocarbon vapors exhausted from the facility shall be installed, maintained, and operated in accordance with the notice of intent dated November 17, 1988, and February 17, 1989. This incinerator shall receive the process effluent from the impregnation autoclave, the carbonization autoclave and the CVD/graphitization furnace. Completion of modifications to building 2440 shall be no later than April 30, 1991.

3. The weaving machines ventilation exhausts shall be

equipped with particulate filters which have a capture efficiency of 95% for 5 μm particles.

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 70 pitch impregnation processes per year
   B. 50 carbonization processes per year
   C. 35 graphitization processes per year
   D. 18 CVD processes per year

   The operations log shall record the amounts of special resins, coal tar pitch, and furfural used in these different processes.

5. All incidents of "vessel rupture" during operations of the HiPIC autoclave shall be recorded in the operations log.

6. The fume incinerator shall be operated and maintained with a minimum temperature of 1500°F. The incinerator temperature shall be monitored with temperature sensing equipment which shall be capable of continuous measurement and readout of the combustion temperature with the readout located such that an inspector/operator can at any time safely read the output. The measurement shall be accurate as specified below. The measurement need not be continuously recorded.

   All instruments shall be calibrated against a primary standard at least once every 180 days. The calibration procedure shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 4.3.

7. The incinerator shall be designed with a minimum effective temperature residence time of 0.5 second at maximum flow rate.

8. All effluent stack/vents for process emissions shall have wire mesh filters to control broken carbon filaments, where applicable, except those stacks vented to the fume incinerators.

Building - 2478 - Solvent Coating And Resin Prep And Handling

1. The installations for the solvent coater shall consist of the following equipment capable of PM_{10} emissions:

   A. MEK fume incinerator
   B. 300 gallon mixer

C. 1 - 300 kw diesel fueled generator set

2. The MEK fume incinerator shall be operated and maintained within a temperature range of 1450°F to 1800°F. The incinerator temperature shall be monitored with temperature sensing equipment which shall be capable of continuous measurement and readout of the combustion temperature with the readout located such that an inspector/operator can at any time safely read the output. The measurement shall be accurate as specified below. The measurement need not be continuously recorded.

   All instruments shall be calibrated against a primary standard at least once every 180 days. The calibration procedure shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 4.3.

   The incinerator shall be designed with a minimum effective temperature residence time of 0.5 second at maximum flow rate.

3. The approved installations/processes for the resin preparation and handling shall consist of the following in accordance with the information submitted in the notice of intent dated December 12, 1985, and the follow up correspondence dated March 21, 1986, and April 11, 1986:

   A. Transfer of powdered curing agents to the hopper shall be done using a Young Conveying System or equivalent system. Equivalency shall be determined by the Executive Secretary. The hopper shall discharge through a feeder into the continuous mixer as a closed system.

   B. Heat sources shall be electrically powered or steam powered from existing plant services. If any other power source is used, a notice of intent shall be filed with the Executive Secretary in accordance with Section 3.1, UACR.

4. All effluent stack/vents for process emissions shall have wire mesh filters to control broken carbon filaments, where applicable, except those stacks vented to the fume incinerators.

Building - 2479 - Graphite Fiber Production, Lines #6 & #7

1. The installations in building 2479 for graphite fiber lines #6 shall consist of only the following equipment:

A. 4 - low temperature natural gas fired oxidation ovens (270°C maximum) with 2 - 2.5 MMBTU/hr burners per oven

B. 1 - low temperature nitrogen purged carbonization furnace (700°C) with 2 natural gas fired exhaust ports (with pilot lights) that precombusts part of the volatiles prior to the fume incinerator

C. 1 - John Zink or equivalent fume incinerator that controls emissions from the low temperature carbonization furnaces

D. 1 - high temperature nitrogen purged carbonization furnace (1450°C) with 2 burner boxes at the furnace entrance equipped with pilot lights to insure that combustion takes place

E. Finishing area shall have water based wash baths:

1 - Ammonium-bicarbonate
2 - Water wash baths

F. Dry type wire mesh air filter devices shall be installed on all hoods and ventilation stacks to control broken carbon filaments except those vented to an incinerator.

G. The following emergency diesel fired electrical generator shall be installed:

One 250 kw Generating capacity

2. The installations in building 2479 for graphite fiber line #7 shall consist of the following equipment capable of PM_{10} emissions:

A. Four low temperature oxidation ovens (270°C maximum). The ovens shall be indirectly heated with 2 - 2.5 MMBTU/hr natural gas fired burners per oven

B. One electrically heated low temperature nitrogen purged tar removal carbonization furnace (750°C) with 1 natural gas fired port (with pilot light) that ensures partial precombustion of the volatiles prior to exhausting into a fume incinerator

C. One electrically heated low temperature nitrogen purged carbonization furnace (900°C) with 2 natural gas fired exhaust ports (with pilot light) that precombusts part of the volatiles prior to the fume incinerator

D. One McGill Inc, or equivalent fume incinerator that controls emissions from both the tar removal and low temperature carbonization furnaces

E. One electrically heated high temperature nitrogen purged carbonization furnace (1450°C) and a burner box (a pilot light shall be included in the burner box to insure that combustion takes place)

F. All effluent stack/vents for process emissions shall have wire mesh filters to control broken carbon filaments, where applicable, except those stacks vented to the fume incinerators.

G. The following emergency diesel fired electrical generators shall be installed:

1. 1 @ 100 kw generating capacity
2. 1 @ 400 kw generating capacity

The above Equipment shall be installed according to the information submitted to the Executive Secretary in the notice of intent dated May 16, 1989, and subsequent information submitted to the date of this SIP.

3. Emissions from line #6 and #7 low temperature carbonization furnaces shall be controlled by a John Zink, McGill, Inc. or equivalent fume incinerator. The following operating parameters for the incinerators shall be maintained within the indicated ranges:

A. Temperature - 1400°F minimum to 1700°F maximum for both incinerators

B. Percent excess O_2 - 6 minimum for line #7 incinerator

4. The incinerators required in conditions 1.C and 1.D above shall be monitored with equipment, where applicable, located such that an inspector/operator may at any time safely read the output. The measurements shall be accurate to within the following ranges:

A. Plus or minus 25°F
B. Plus or minus 5% of full scale (0 to 10% scale)

The incinerator monitors shall be capable of continuous measurement and readout of the monitor values shall be located such that an inspector/operator can at any time safely read the output. The measurement need not be continuously recorded. All monitors shall be calibrated against a primary standard at least once every 180 days. The calibration procedure for the temperature monitor shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 4.3. The calibration procedure for the excess air monitor shall be in accordance with 40 CFR 60, Appendix A, Method 3.

5. The incinerator shall be designed with a minimum effective temperature residence time of 1.0 second at maximum temperature and flow rate.

Building - 8162 R & D Facility For New Processes

1. The installations in building 8162 for research and development of new products and processes shall consist of the following equipment:

   A. A pilot size fiber line with various ovens, furnaces, and process as necessary for research and development purposes

   B. John Zink, McGill, or equivalent incinerator system rated at 750,000 BTU/hr with a 3/1 turndown.

2. The emissions from each high temperature nitrogen purged carbonization furnace shall have a burner box (a pilot light shall be included in the burner box to insure that combustion takes place).

4. Emissions from the low temperature carbonization furnaces shall be controlled by a John Zink, McGill, Inc., or equivalent fume incinerators. The following operating parameters for the incinerator shall be maintained within the indicated ranges:

   A. Temperature - 1400°F minimum to 1700°F maximum
   B. Percent of excess O_2 - 6% minimum

5. The incinerators shall be monitored with equipment located such that an inspector/operator may at any time safely read
the output. The measurements shall be accurate to within the following ranges:

   A. Plus or minus 25°F
   B. Plus or minus 5% of full scale (0 to 10% scale)

   The incinerator monitors shall be capable of continuous measurement and readout of the monitor values located such that an inspector/operator can at any time safely read the output. The measurement need not be continuously recorded. All monitors shall be calibrated against a primary standard at least once every 180 days. The calibration procedure for the temperature monitor shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 4.3. The calibration procedure for the excess air monitor shall be in accordance with 40 CFR 60, Appendix A, Method 3.

6. The incinerator shall be designed with a minimum residence time of 1.0 second at maximum temperature and flow rate.

7. The facility shall be used for development of new fiber products and new process development only and not as a production facility.

2.2.U Interstate Brick Company

1. Interstate Brick Company, located at 9780 South 5200 West, West Jordan, Utah, shall operate the brick/tile production plant according to the following conditions.

2. The installations shall consist of only the following equipment:

   A. Tunnel Kiln #1
   B. Tunnel Kiln #3
   C. Tunnel Kiln #4
   D. Shuttle Kiln (#5)
   E. Grizzly Hopper
   F. Primary Crusher
   G. Secondary Crusher/Grinding
   H. Screens
   I. 2 Lime Silos
   J. Clay Storage Piles
   K. Miscellaneous Diesel Equipment

3. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Tunnel Kiln #1;

1.	PM_{10}	2.6	lbs/hr	0.028	grains/dscf
2.	NO_x	2.5	lbs/hr	32	ppmdv

   B. Tunnel Kiln #3

1.	PM_{10}	3.1	lbs/hr	0.028	grains/dscf
2.	NO_x	3.0	lbs/hr	33	ppmdv

   C. Tunnel Kiln #4

1.	PM_{10}	12.3	lbs/hr	0.039	grains/dscf
2.	NO_x	6.0	lbs/hr	23	ppmdv

   D. Shuttle Kiln

1.	PM_{10}	1.6	lbs/hr	0.028	grains/dscf
2.	NO_x	0.18	lbs/hr	3.9	ppmdv

   E. Primary Crusher Baghouse Vent

1.	PM_{10}	0.49	lbs/hr	0.016	grains/dscf

   F. See note at end of subsection on need to perform SO_2 testing

4. Stack testing to show compliance with the above emission limitations shall be performed for the following emission

points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

	Point		Method	Retest every
A.	Tunnel Kiln		#1	
	1.	PM_{10}	201/201a	Test if Directed
	2.	NO_x	7	Test if Directed
B.	Tunnel Kiln		#3	
	1.	PM_{10}	201/201a	Test if Directed
	2.	NO_x	7	Test if Directed
C.	Tunnel Kiln		#4	
	1.	PM_{10}	201/201a	3 years
	2.	NO_x	7	3 years
D.	Shuttle Kiln			
	1.	PM_{10}	201/201a	Test if Directed
	2.	NO_x	7	Test if Directed
E.	Primary Crusher			
	1.	PM_{10}	201/201a	3 years

5. The following limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. Raw Clay Consumption:

120 tons/hr
1,051,200 tons/yr

B. Tunnel Kiln #1:

5000 hours/yr
68,250 tons of brick/year

C. Tunnel Kiln #3:

148,044 tons of brick/year

D. Tunnel Kiln #4:

291,288 tons of brick/year

E. Shuttle Kiln #5:

X3

5000 hours/yr
5000 tons of tile/year

Records of production shall be kept for each of the above listed sources.

6. The moisture content of the clay feed shall be maintained at a value of no less than 4.0% by weight. The silt content of the clay shall not exceed 18.0% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

7. The owner/operator shall use only natural gas as fuel in the brick/tile kilns. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

8. Annual emissions for this source (the entire plant) are hereby established at 96 tons/yr for PM_{10}, 0.04 tons/yr for SO_2, and 46 tons/yr for NO_x.

Note: There is a need to have Interstate Brick perform stack testing of their kilns while processing different type brick/tile materials. The SO_2 emission levels are not known as of this time of PM_{10} SIP finalization. Interstate Brick shall conduct the adequate esting using proper EPA Test Methods to quantify SO_2 emission evels from manufacturing operations and submit a notice of intent to the executive secretary not later than September 1, 1992 in accordance with Section 3.1.1, UACR to reduce SO_2 emissions as required by the SIP (RACT). The modifications to reduce SO_2 emissions shall be completed not later than December 10, 1993.

From Section 9 Appendix A, Emission Limitations and Operating Practices (Updated 15 April 1992) only pages 100-143

2.2.V Kennecott Utah Copper Smelter

2.2.V.A General Conditions

1. The approved installations shall consist of only the following equipment:

   A. Smelter vessels (3 reactors, 4 converters)
   B. Acid plant(s)
   C. Smelter Powerhouse (3 boilers, 2 superheaters)
   D. Rotary Concentrate Dryers
   E. Anode Furnaces (3)
   F. Crushing and grinding operations
   G. Miscellaneous diesel equipment
   H. Support facilities

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Smelter Powerhouse, total

   NO_x - 20.8 lb/hr   80.9 ppmdv

   B. Rotary Concentrate Dryer Stack

   PM_{10} - 4.2 lb/hr   0.018 gr/dscf
   NO_x - 7.1 lb/hr   67 ppmdv

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, and as directed by the Executive Secretary:

	Test Every
Rotary Concentrate Dryer	
PM_{10}	1 year

4. Visible emissions from the following emission points shall not exceed the following values:

A.	Smelter Powerhouse	10% opacity
B.	Rotary Concentrate Dryer Stack	15% opacity
C.	All Baghouses	10% opacity
D.	Crushing and Screening Operations	15% opacity

E. Fugitive Dust 20% opacity

5. Opacity observations of emissions from all stationary sources other than the main stack shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

6. Water sprays, chemical dust suppression sprays or dust collectors shall be operated if necessary at the following points to maintain less than 15% opacity:

   A. All crushers
   B. All screens
   C. All crushed slag conveyor transfer points

7. The owner/operator shall use only natural gas as fuel in the sources listed below:

   A. Powerhouse
   B. Rotary Dryer

   Fuel consumption shall not exceed the following level from the above sources consolidated:

   Natural gas 1100 million cu-ft/calendar yr

   Fuel oil (#2) or lighter shall be permitted in the event of a curtailment of natural gas. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. Fuel consumption shall be determined by plant records.

8. Owner/operator shall employ the following measures for reducing escape of pollutants to the atmosphere and to capture emissions and vent them through a stack or stacks:

   A. Maintenance of all ducts, flues, and stacks in such a fashion that leakage of gases to the ambient air will be prevented to the maximum extent practicable;

   B. Operation and maintenance of primary and secondary collection systems in good working order;

   C. Making available to the Executive Secretary the preventive/routine maintenance records for the primary and secondary hooding systems; dust collection mechanism of waste heat boilers, dropout chambers and shot coolers; hot cyclones; and dry electrostatic precipitators;

   D. Daily observation of process units;

E. Daily inspection of gas handling systems;

F. Monthly monitoring of SO_2 emission concentrations at all preheater stacks and at the waste heat boiler vents during periods of operation of these sources;

G. Maintenance of gas handling systems, available on call on a 24-hour basis;

H. Operation and maintenance of an upwind/downwind fugitive monitoring system (EPA 600/2-76-089a, April 1976);

I. Contained conveyance of acid plant effluent solutions.

Within 90 days of Committee approval of these conditions, Kennecott will submit to the Bureau examples of the forms and records that will be used to comply with subsection 8.D, 8.E, and 8.F above.

9. Compliance with the main stack mass emission limit for particulate matter of condition 2.2.V.B(1A) shall be demonstrated using the smelter main stack continuous particulate sampling system to provide a 24-hour value. Collected data shall be available for inspection daily, and summary of 24 hour averages shall be submitted to the Executive Secretary monthly (within 15 days of end of month).

10. To demonstrate compliance with the main stack mass emission limit for SO_2 of condition 2.2.V.B(1B), Kennecott shall calibrate, maintain and operate the measurement system for continuously monitoring sulfur dioxide concentrations and stack gas volumetric flow rates in the main smelter stack. The continuous SO_2 monitoring system described in this subsection shall meet the following requirements:

A. Kennecott shall comply with all applicable parts of Section 4.6, UACR "Continuous Emission Monitoring Systems Program", including the requirements for annual Relative Accuracy Test Audits and quarterly Relative Accuracy Audits or Cylinder Gas Audits. In addition, Kennecott shall conduct quarterly Calibration Error, Calibration Drift, and Zero Drift Tests (24 hour, 5 data points). The required Relative Accuracy Test Audits, Relative Accuracy Audits, Calibration Error Tests, Zero and Calibration Drift Tests shall be conducted following Procedures contained in Appendix D, Part 52, Title 40, CFR. The required Cylinder Gas Audits shall be conducted following procedures contained in 40 CFR Part 60, Appendix F. All audit and test results shall be submitted to the Executive Secretary, Utah Air Conservation Committee (UACC) within 30 days after the audit or test is completed.

B. Kennecott shall perform Appendix E, Part 52, Title 40, CFR Performance Specification procedures on the stack gas flow rate measurement system, if directed by the Executive Secretary, in the event that the results of the quarterly and annual tests required by condition 10.A demonstrate that the SO_2 monitoring system is not performing properly.

C. Kennecott shall maintain a record of all measurements required by this condition 10. Measurement results shall be expressed as pounds of sulfur dioxide emitted per hour calculated at the end of each day for the preceding 24 hours, and calculated at the end of each hour for the preceeding three hour period. Results for each measurement or monitoring system and reports evaluating the performance of such systems shall be summarized and shall be submitted to the Executive Secretary within 15 days after the end of each month. The Executive Secretary, in consultation with Kennecott, shall determine an acceptable format for reporting such results and system evaluations. The following measurements, expressed as lbs/hr sulfur dioxide, shall also be summarized and submitted in such report(s):

1. The total number of hourly periods during the month in which measurements were not taken.

2. For any periods where loss of measurement is greater than 3 continuous hours, the reason for loss of measurement in each period.

3. The date(s) on which 24 hour emissions averages exceeded the applicable emission level in condition 2.B in the month being reported and the number of such exceedances.

4. All conversion values used to derive the 24 hour and 3-hour average emissions for SO_2, including temperature and differential pressure of stack gases.

D. Failure of Kennecott to measure at least ninety-five percent (95%) of the hours during which emissions occurred in any month in accordance with the requirements of this subsection, or failure to measure, in accordance with the requirements of this subsection, any 18 consecutive hours of emissions data shall constitute a violation of this condition 10. Any hour for which the measurements comply with UACR 4.6 shall be considered as measured. Calibration shall be performed once per day; the hour during which calibration is performed shall be considered as measured if at least 40 minutes of data are measured for that hour. Any hours for which the emissions data are greater than 20% in error will be considered to have not been measured for the purposes of this condition 10. The Executive Secretary may grant exemptions to the requirements of this condition 10 if unusual circumstances, not to include malfunction of any of the monitoring instrumentation, arise which prevent Kennecott from obtaining hourly measurements of emissions in accordance with this condition 10.

E. During periods of malfunctioning or maintenance of the stack gas temperature and velocity measurement instrumentation, owner/operator may estimate stack gas flow rate. Such estimates will be considered as measurements for the purpose of this condition 10. Calculations used to derive the estimated flow rate and a list of the periods where stack gas flow rate was estimated in each month shall be submitted with the monthly data reports. No more than 10% of the flow rates in any one month may be estimated.

F. For data, reports, or results required to be submitted to the Executive Secretary pursuant to this condition 10, unless, within 30 days of the time such data results are submitted, the owner/operator or the Executive Secretary provides evidence that the data, results, or reports or any part thereof are greater than 20% in error; such data, reports or results will be deemed to be verified and accepted as valid and not subject to challenge and shall be used by the Executive Secretary and the Committee in determining compliance with condition 2.B.

11. Compliance with the main stack opacity limits set forth in condition 2.2.V.B(2) and 2.2.V.C(5) shall be demonstrated with a continuous opacity monitor on the

main stack, which shall comply with the specifications of Section 4.6 of the UACR.

12. Startup and Shutdown:

A. All gases produced during smelting which enter the primary hoods shall pass through an on-line sulfuric acid plant. If on-line acid plant capacity is degraded, the owner/operator shall adjust blowing rates, modify production sequence, or curtail production by rolling out vessels and cease the pumping of air into them until primary hood emissions can all pass through an on-line acid plant. If all on-line acid plant capacity is degraded, the owner/operator shall roll out all vessels and cease the pumping of air into them. No vessel shall be rolled back into the primary hoods again until such time as the first pass catalyst bed reaches 360°C (680°F).

If any charged converter vessel is required to be rolled out for more than 16 hours, the owner/operator may continue operation of the charged vessel only until that charge is completed. Failure to comply with these curtailment requirements shall constitute a violation of this condition 12.

B. No acid plant may be in startup/shutdown mode for more than 5 % of the hours when the smelter is operating (i.e. when air is being pumped into one or more smelting vessels). Compliance with this condition in no way releases the owner or operator from any liability for compliance with any other applicable conditions.

For an acid plant, "startup/shutdown mode" shall be defined as:

(a) the time period beginning when on-line acid plant capacity is degraded and ending when the owner/operator completes the applicable operating changes described in the second and third sentences in paragraph 2.2.V.A.12(A); and

(b) the time period beginning with startup of the acid plant and ending with achievement of steady-state acid plant operations, not to exceed 6 hours.

Except as provided in Condition C(2), all emissions during acid plant startup/shutdown mode shall be included in calculating compliance with emission limits.

C. If an acid plant has been off-line for more than 18 hours, the following conditions apply:

(1) The owner/operator shall notify the Executive Secretary by telephone when acid plant startup begins.

(2) Emissions during the first 4 hours of acid plant startup shall not be included in calculating compliance with either the 3-hr, or the 24-hr average emission limits.

D. Scheduled acid plant overhauls must be planned for the annual period from March 1 through October 31.

E. Within 90 days of the effective date of this section, owner/operator shall provide to the Executive Secretary for his information a plan for minimizing emissions during startup.

13. This section (2.2.V.A) is effective upon adoption by the Committee.

2.2.V.B Additional Conditions

1. Emissions to the atmosphere from the smelter main stack shall not exceed the following rates and concentrations:

   A. PM_{10} - 400 lb/hr, 24 hour average (calendar day) as defined pursuant to condition 2.2.V.C (5D); 200 lb/hr, annual average, as defined pursuant to condition 2.2.V.C (5D).

   B. SO_2 - 6,450 lb/hr, 3 hour average (rolling); 5,700 lb/hr, 24 hour average (calendar day); 3,240 lb/hr, annual average

   C. Acid plant tail gas - 1200 lb SO_2 /hr measured as a six hour average, 650 ppmvd measured as a six hour average; 1,950 lb SO_2 /hr measured as a three hour average (rolling), 1,050 ppmdv mesured as a three hour average (rolling).

   The limits above are based upon double contact acid plant technology. In the event of construction or permitting delays associated with new process or control equipment, during the performance test period under 40 CFR 60.8, or otherwise as authorized by the Executive Secretary, Kennecott may comply with the emission limits in this paragraph by any combination of control technologies, production methods or work practices which achieves the emissions in subparagraphs A and B to the extent allowable by the Federal Clean Air Act. Kennecott shall submit progress reports to the Executive Secretary once per quarter until completion of construction. If delays are experienced which may affect the date of plant startup, Kennecott shall so note in the quarterly report.

2. Visible emissions from main tall stack and smelter building roof vents shall not exceed 20% opacity based upon Method 9, provided that:

   A. The opacity limit is applicable as defined in 40 CFR 60.11(c);

   B. Kennecott fails to submit a petition as described in 40 CFR 60.11(e)(6);

   C. Kennecott fails to make the demonstration required in 40 CFR 60.11(e)(7) and (8).

3. Compliance with the mass emission limit for SO_2 in acid

plant tail gas set forth in condition 2.2.V.B(1C) shall be demonstrated with a continuous emission monitor on the tail gas duct(s) of the acid plant(s). The CEM system installed on the acid plant(s) shall report 24 hour averages and comply with the specifications of Section 4.6 of the UACR.

4. Annual emission for this source (the entire smelter plant) are hereby established at 1340 tons/yr for PM_{10}, 18,575 tons/yr for SO_2, 145 tons/yr for NO_x.

5. The effective date of this section 2.2.V.B shall be determined in accordance with sections 3.2.5 and 3.2.6 of the UACR; with the exception of the three-hour SO_2 limits on the acid plant tail-gas and the tall stack.

6. The effective date of the three-hour SO_2 limits on the acid plant tail-gas and the tall stack shall be as expeditiously as practicable, but no later than November 15, 1995.

2.2.V.C Temporary Conditions

1. Visible emissions from the following emission points shall not exceed the following values:

   A. Main stack opacity, as measured by CEM, limit and averaging period to be determined according to Condition 2.2.V.C (5A & 5B)

   B. Smelter building roof vents to be determined according to Condition 2.2.V.C (5F)

   C. Reactor vent stacks to be determined according to condition 2.2.V.C (5E)

   Note: When the opacity limitations are determined for the sources in A, B, and C, the opacity limitations shall then be established by order of the committee.

2. Emissions to the atmosphere from the smelter main stack shall not exceed the following rates:

   A. TSP - 545 lb/hr, 24 hour average (calendar day);
   B. SO_2 - 8,979 lb/hr, 24 hour average (calendar day).

3. For control of smelter emissions other than from the main stack, the owner/operator shall:

   A. By December 31, 1991, install redesigned primary hooding at reactors #2 and #3 slag skimming and matte tapping operations.

   B. By December 31, 1991, install redesigned primary hooding and replace flues on converters.

   C. By December 31, 1991, install automatic tuyere punchers on reactors #2 and #3.

   D. By December 31, 1991, replace preheaters on acid plants #7 and #8.

   E. By December 31, 1991, install hoods over the #2 and #3 reactor bath measuring stations.

   F. By December 10, 1993, capture emissions from reactor vessel vents into secondary capture system.

4. Within 90 days after SIP promulgation by the committee, Kennecott shall submit to the Executive Secretary:

A. A complete schedule for design and construction required for compliance with the conditions 2.2.V.C(3A-F).

B. A notice of intent to construct in accordance with the procedures of Section 3.1, UACR for compliance with the conditions 2.2.V.C(3E and F).

5. The studies and reports listed below shall be accomplished to determine the appropriate emission limitations and to determine if 20% opacity limitations are achievable while appropriate emission control devices and work practices are observed to be in effect, and smelting operations are within 90% of maximum production rates achieved in the previous 3 years. All methods of determining control equipment effectiveness, stack testing methods and study protocols shall be determined in a pretest conference between Kennecott and representatives of the Executive Secretary at least 45 days prior to any studies. The studies shall be performed, the results submitted to the Executive Secretary of the Utah Air Conservation Committee, and the limitations established within the indicated time periods following the designated milestones:

	Emission Point	Item to be Determined	Test Report and New Limitations Due Within
A.	Main stack	Interim CEM opacity limit & averaging period	6 months after promulgation of SLCo SIP by UACC
B.	Main stack	Interim CEM opacity limit & averaging period	6 months after capture of emissions from reactor vessel vents into secondary capture system
C.	Main stack	Final CEM opacity limit & averaging period	6 months after new acid plant becomes operational
D.	Main stack	PM_{10}/TSP ratio	6 months after new acid plant becomes operational

E.	Reactor vent stacks	Interim opacity decay limits	6 months after promulgation of SLCo SIP by UACC
F.	Hot metals building roof vents	Interim opacity	6 months after promulgation of SLCo SIP by UACC
G.	Hot metals building roof vents	Final opacity	6 months after primary and secondary ducting modifications become operational

6. Kennecott shall monitor acid plant sulfur recovery efficiency, and shall provide the following data to the Executive Secretary in the monthly report required by condition 2.2.V.A (10) including the following parameters:

   A. Total gas volume produced in DSCF (68 °F, 29.92 inches Hg, Dry)

   B. Concentration of SO_2 in mole percent

   C. Quantity of H_2SO_4 produced

   D. Availability of each acid plant in total hours for the month

   E. Owner/operator shall report to the Executive Secretary the percent of time in startup/shutdown mode for each acid plant in the monthly report required by condition 2.2.V.A(10). Percent of time in startup/shutdown mode shall be defined by the following equation for each plant:

$$\frac{\text{Hours that the acid plant is in startup/shutdown mode} \times 100}{\text{hours smelting time}^{*}}$$

** Definition: Smelting time = When air is being blown into the smelting vessels.*

7. This section 2.2.V.C is effective upon adoption by the committee and shall terminate on the effective date of section 2.2.V.B.

2.2.W Kennecott Utah Copper - Bingham Canyon Mine

1. The approved installations shall consist of only the following equipment located at the site:

   A. Crushers
   B. Conveyors
   C. Haul Trucks
   D. Loaders
   E. Graders
   F. Bulldozers, Scrapers
   G. Drills
   H. Lime Silo
   I. Water Trucks
   J. Utility Vehicles
   K. Diesel Locomotives
   L. Various small engine powered mobile equipment

2. Total material moved (ore and waste) shall not exceed 150,500,000 tons per 12-month period without prior approval in accordance with Section 3.1, UACR. Compliance with the throughput limitation shall be determined on a rolling-annual total reported on a monthly basis. On the first day of each new month, a new 12-month total shall be calculated using the previous 12 months. Records of throughput shall be kept for all periods when the mine is in operation. Records of throughput shall be made available to the Executive Secretary of the Utah Air Conservation Committee upon request, and shall include a period of two years ending with the date of the request. Total material moved shall be determined by the use of daily haulage reports.

3. Visible emissions from the following emission points shall not exceed the following values:

   A. Crushers - 7% opacity
   B. Conveyor transfer points equipped with baghouses - 7% opacity
   C. All other conveyor transfer points - 10% opacity
   D. Lime silo - 10% opacity
   E. Unpaved ore haul roads, front-end loading, truck dumping, stockpiles, blasting area - minimize emissions
   F. Drilling - 10% opacity
   G. All other points - 10% opacity

   Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

4. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

A. In-pit Crusher Baghouse Vent

PM_{10}	1.77 lbs/hr	0.016 grains/dscf

B. Two (2) Controlled Drop Point Baghouse Vents Near Copperton

PM_{10}	0.22 lbs/hr	0.016 grains/dscf

5. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, and as directed by the Executive Secretary:

A. In-pit Crusher Baghouse Vent - PM_{10} 201/201a (Test every 3 years)

B. Two (2) Controlled Drop Point Baghouse Vents Near Copperton - PM_{10} 201/201a, (Test every 3 years)

6. The height of the mine waste dump lift shall not exceed 1000 feet.

7. The owner/operator shall provide to the Executive Secretary for approval a plan to keep trigger opacity on active waste slopes at less than 20% opacity. Average opacity emissions from the active waste dump push slopes shall not exceed 20%. To insure that 20% opacity is not exceeded, the waste dump slopes shall be monitored by Kennecott.

If the 20% trigger opacity limitation cannot be met on any waste dump slope, action shall be initiated to prevent excesses of 20% trigger opacity by applying additional and/or alternate control measures, as defined in the fugitive dust control plan, as approved by the Executive Secretary.

Trigger opacity observations shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9 with the following exceptions:

Opacity observations shall only be taken while a batch of dumped material is in motion.

One reading shall consist of an accumulation of three (3) minutes of trigger opacity observations taken over the material in motion.

8. If Kennecott or the Executive Secretary, UACC determines that the trigger opacity is being exceeded and existing alternate control measures have been exhausted, Kennecott shall meet with the Executive Secretary, or his staff, to discuss additional or modified fugitive dust controls/operational practices and an implementation schedule for such within five working days after verbal notification by either party.

9. Kennecott Utah Copper will use frequent watering or approved chemical dust suppressant to control road dust from all trafficked roads and areas in the mine. Kennecott Utah Copper will submit an annual road dust control report, in conjunction with the fugitive dust control plan, by February 1 of each calendar year, containing as a minimum the following:

   A. A description of what dust control measures are planned for the coming year.

   B. A report of what dust control measures were actually completed during the past year.

   C. Specific elements of the report will include:

      1. A map of all trafficked areas and roads associated with the mine, indicating which areas are planned for treatments with water and/or chemical dust suppressant.

      2. A description of what chemical dust suppressant will be used if used and how it will be applied (application rate, application frequency, dilution rate, special application procedure, scarification, etc.).

      3. A list of equipment dedicated either full or part time to work area and road dust control (# of water trucks, water capacity, # graders, etc.).

      4. A quantification of how much dust suppressant (gallons, tons) was applied the previous year, and when and where it was applied.

      5. A quantification of how much watering was

accomplished the previous year (gallons, water truck operating hours).

10. The following operating parameters shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

    A. Maximum daily total mileage for haul trucks (30,000 miles)

    B. Minimum design payload per haul truck (150 tons)

    C. Maximum number of wheels per haul truck (6 wheels)

    D. Any new haul trucks purchased will be rated at the indicated minimum net payload weight (190 tons)

11. Wet drilling shall be performed for all blast holes.

12. The lime silo shall be equipped with a fabric type bin vent control unit.

13. All uncovered storage piles shall be sprayed with water or dust suppressants as dry conditions warrant or as determined necessary by the Executive Secretary.

14. The sulfur content of diesel fuel oil burned in the equipment engines shall not exceed 0.21 pound of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. (This represents 0.4% sulfur by weight in the fuel oil, 137,000 btu/gal, and 7.05 lb/gal). After December 31, 1993, the sulfur content of diesel fuel oil burned in the equipment engines shall not exceed 0.03 pound of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. (This represents 0.05% sulfur by weight in the fuel oil, 137,000 btu/gal, and 7.05 lb/gal). The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall not exceed 27,500,000 gal/yr. Fuel consumption shall be determined by mine records of diesel fuel oil purchased.

15. In addition to the requirements of this approval order, all provisions of 40 CFR 60, NSPS Subparts A and LL apply to the mineral processing portion of this source.

16. For sources which are subject to NSPS, visible emission observations which are performed during the initial compliance inspection shall consist of 30 observations of six minutes each in accordance with 40 CFR 60, Appendix A, Method 9. It is the responsibility of the

owner/operator of the source(s) to supply these observations to the Executive Secretary. Emission points which are subject to NSPS shall include the following:

A. All ore crushers
B. All conveyor transfer points associated with the crushing and conveying of ore

17. All installations and facilities authorized by this approval order shall be adequately and properly maintained.

18. Annual emissions for this source (the entire Bingham Canyon pit and ore handling operations) are currently calculated at 2801 tons/yr for PM_{10}, 78 tons/yr for SO_2, 4048 tons/yr for NO_x.

2.2.X Kennecott Utah Copper - Copperton Concentrator

1. The approved installations shall consist of the following emission points located at the site:

   A. Feed Molybdenite Dryers with Venturi Scrubbers
   B. Feed Molybdenite Dryer Heaters
   C. Molybdenite Heat Treater with Venturi Scrubber
   D. Molybdenite Heat Treater Heater
   E. Product Molybdenite Dryers with Venturi Scrubbers
   F. Steam Boiler (10,000 lb/hour)
   G. Molybdenite Storage Bins with Baghouse
   H. Molybdenite Storage/Loading Facilities with Baghouses
   I. Soda Ash Storage Silo with Baghouse
   J. Vacuum Cleaning System with Baghouse
   K. Other Associated Equipment

2. Visible emissions from the following emission points shall not exceed the following values:

   A. Baghouse Stack on Molybdenite Storage Bin (Subject to NSPS, Subpart LL) - 7% opacity
   B. Baghouses on Molybdenite Storage/Loading Facilities (subject to NSPS, Subpart LL) - 7% opacity
   C. Fugitive emission points (subject to NSPS, Subpart LL) - 10% opacity
   D. All other points - 10% opacity

3. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

4. In addition to the requirements of this approval order, all provisions of 40 CFR 60, NSPS, Subparts A and LL apply to the mineral processing portion of this source.

5. All installations and facilities authorized by this approval order shall be adequately and properly maintained.

6. The following operating parameters shall be continuously monitored:

   A. Pressure drop (± one inch of water) through every wet scrubber
   B. Liquid flow rate (± 5% of design flow rate) through every wet scrubber
   C. pH (± 0.5 s.u.) in flotation circuit upstream of leach circuit

All of the wet scrubbers shall comply with 40 CFR 60.384 and 60.385.

7. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

A. Feed Molybdenite Dryers

PM_{10}	0.25 lbs/hr	0.016 grains/dscf

B. Molybdenite Heat Treater

1.	PM_{10}	0.20 lbs/hr	0.016 grains/dscf
2.	SO_2	26.2 lbs/hr	1,455 ppmdv

C. Product Molybdenite Dryers

PM_{10}	0.15 lbs/hr	0.016 grains/dscf

D. Molybdenite Storage Bins

PM_{10}	0.21 lbs/hr	0.016 grains/dscf

E. Molybdenite Storage and Loading Facilities

PM_{10}	0.07 lbs/hr	0.016 grains/dscf

8. Stack testing to show compliance with the emission limitation of condition number 7 shall be performed in accordance with 40 CFR 60, Appendix A; 40 CFR 51 Appendix M (see paragraph 2.1A for more details) and as directed by the Executive Secretary. The following emission points shall be tested for the indicated air contaminants by the indicated test method at the indicated schedule:

<u>Source</u>	<u>Pollutant</u>	<u>Method</u>	<u>Test Every</u>
Feed Molybdenite Dryers	PM_{10}	5	Test if directed
Molybdenite Heat Treater	PM_{10}	5	Test if directed
	SO_2	CEM UACR4.6	5 years Relative Accuracy Test
Product Molybdenite Dryers	PM_{10}	5	Test if directed

Molybdenite Storage PM_{10} Bins	201/201a	Test if directed
Molybdenite Storage PM_{10} and Loading Facilities	201/201a	Test if directed

9. The owner/operator shall use only natural gas or LPG as a fuel in the combustion sources. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

10. For sources which are subject to New Source Performance Standards (NSPS), visible emission observations which are performed during the initial compliance inspection shall consist of 30 observations of six minutes each in accordance with 40 CFR 60, Appendix A, Method 9.

    It is the responsibility of the owner/operator of the source(s) to supply these observations to the Executive Secretary. Emission points which are subject to NSPS shall include the following:

    A. Molybdenite Heat Treater
    B. Feed Molybdenite Dryers
    C. Product Molybdenite Dryer
    D. Storage and shipping facilities

11. The pH of the cyanide leach circuit shall be maintained at a value of no less than 9.5.

12. Natural gas consumption shall not exceed the following limitations for the equipment listed:

Molybdenite Heat Treater	4.8×10^6 SCF per 30 days
Feed Molybdenite Dryers (each)	4.1×10^6 SCF per 30 days
Steam Boiler	12.0×10^6 SCF per 30 days

    Records of consumption shall be kept for all periods when the plant is in operation. Records of consumption shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request. Natural gas shall be metered at each location.

13. The Molybdenite Heat Treater shall be operated as a dryer with water as the Scrubbing Solution in the venturi scrubber. When used as a heat treater, the following measures shall be taken:

    A. The SO_2 scrubber will be fully activated.

B. The installed continuous emissions monitor (CEM) shall be used to determine compliance with the SO_2 limitation (26.2 lb/hr) on an hourly basis.

C. The monitor shall meet all requirements listed in Section 4.6, UACR.

D. Quarterly reports of the results of continuous emissions monitoring shall be submitted to the Executive Secretary during any quarter in which the heat treatment process was used. The reports shall include all excess emission episodes.

E. The CEM shall be calibrated and the results reported on the following schedule:

1. Quarterly calibration results submitted with the quarterly reports.

2. Calibration of the CEM within 24 hours of any transition of the heat treater from dryer mode to heat treater mode or heat treating operations shall be discontinued.

F. All continuous monitoring data shall be kept for a minimum of two years after the date on which emissions occurred and shall be made available to the Executive Secretary upon request.

14. Annual emissions for this source (the entire plant site) are currently calculated at 5.1 tons/yr for PM_{10}, 114.9 tons/yr for SO_2, 20.6 tons/yr for NO_x.

2.2.Y Kennecott Utah Copper Refinery, Garfield, Utah

1. The installations shall consist of only the following emission points:

   A. Anode furnace with baghouse
   B. Anode furnace charge slot with baghouse
   C. Selenium extraction process
   D. 2 Dore' furnaces with a wet scrubber and an electrostatic precipitator
   E. Dore' secondary hoods with a baghouse
   F. Dore' slag crusher with baghouse
   G. Selenium refining process with electrostatic precipitator
   H. 2 boilers, rated at 67.4 mmBtu/hr heat input each
   I. Other associated equipment

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

A.	Anode furnace with a baghouse;		
	PM_{10}	0.88 lbs/hr	0.016 grains/dscf
B.	Anode furnace charge slot with a baghouse;		
	PM_{10}	0.62 lbs/hr	0.016 grains/dscf
C.	Selenium extraction process;		
	PM_{10}	0.38 lbs/hr	0.035 grains/dscf
D.	Dore' furnace electrostatic precipitator;		
	PM_{10}	2.85 lb/hr	0.035 grains/dscf
E.	Dore' secondary hood baghouse;		
	PM_{10}	2.70 lb/hr	0.016 grains/dscf
F.	Dore' slag crusher baghouse;		
	PM_{10}	2.70 lb/hr	0.016 grains/dscf
G.	Boilers;		
	1) PM_{10}	0.038 lb/mmBtu heat input	
	2) SO_2	0.96 lb/mmBtu heat input	
	3) NO_x	0.6 lb/mmBtu heat input	

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A for more details), and as directed by

the Executive Secretary:

	Method	Test Every
A. Anode furnace with a baghouse;		
	PM_{10} 201/201a	Test if directed
B. Anode furnace charge slot with a baghouse;		
	PM_{10} 201/201a	Test if directed
C. Selenium extraction process;		
	PM_{10} 201/201a	Test if directed
D. Dore' furnace electrostatic precipitator;		
	PM_{10} 201/201a	3 years
E. Dore' secondary hood baghouse;		
	PM_{10} 201/201a	Test if directed
F. Dore' slag crusher baghouse;		
	PM_{10} 201/201a	Test if directed
G. Boilers;		
	PM_{10} 201/201a	Test if directed
	SO_2	Test if directed
	NO_x 7	Test if directed

4. Visible emissions from the following emission points shall not exceed the following values:

A.	Anode furnace baghouse	10% opacity
B.	Anode furnace charge slot baghouse	10% opacity
C.	Selenium extraction process	20% opacity
D.	Dore' furnace electrostatic precipitator	20% opacity
E.	Dore' secondary hood baghouse	10% opacity
F.	Dore' slag crusher baghouse	10% opacity
G.	Selenium refining process electrostatic precipitator	15% opacity
H.	2 boilers	20% opacity
I.	Other associated equipment	20% opacity

5. The owner/operator shall operate the selenium extraction process in a manner which minimizes the emissions of SO_2. The owner/operator shall perform the following measurements to verify the SO_2 emission rate from the circulation tank stack:

A. Continuously monitor the SO_2 addition rate

B. Monitor the raw material feed rate whenever a charge of de-copperized slimes is added to the selenium extraction process

C. Analyze on a daily basis for soluble selenium (H_2SeO_3) in the circulating solution

D. Monitor the SO_2 concentration in the circulation tank stack (continuous monitoring is not required).

The above measurements shall be taken at least once per day. All data from these measurements shall be kept for a period of two years from the date of the measurement. For the monitor on the stack, the following calibration and maintenance procedures shall be performed:

A. Weekly calibration of the instrument against a span gas of standard concentration which is applicable to this source

B. Quarterly audits of the instrument against three span gases in accordance with 40 CFR 60, Appendix B, Specification 2.

6. The Dore' furnace secondary hood baghouse shall be capable of handling 25,000 acfm. The air/cloth ratio shall not exceed 5.56:1. All exhaust emissions from the Dore' secondary hoods shall pass through the baghouse before being vented to the atmosphere.

7. Fuel consumption for all stationary sources shall not exceed 601,000 million Btu per year, of which no more than 293,000 million Btu shall be in the form of coal. No more that 6,000 million Btu per year of fuel oil #2 or lighter may be burned in the copper melting barrel furnace and arc furnace preheater.

8. The owner/operator shall use fuels in the sources as indicated below:

Source	**Before November 1, 1992; March 1 through October 31 of each year after 1992 (Three Seasons)**	**Winter (November 1 through the last day in February) after October 31, 1992**

		Normal natural gas supply	When the natural gas supply is interrupted by supplier or transporter
2 Boilers	Coal, #2 Fuel Oil or Lighter, LPG, or Natural Gas	Natural Gas or LPG	Coal, #2 Fuel Oil or Lighter, LPG, or Natural Gas
Copper Melting Barrel Furnace and Arc Furnace Preheater	#2 Fuel Oil or Lighter, LPG, or Natural Gas	#2 Fuel Oil or Lighter, LPG, or Natural Gas	#2 Fuel Oil or Lighter, LPG, or Natural Gas
All Other Stationary Fuel Burning Sources	Natural Gas or LPG	Natural Gas or LPG	Natural Gas or LPG

When coal is burned, it shall not have the potential to emit more than 0.96 pounds of SO_2 per million Btu of heat input. Within 48 hours after being informed of a winter curtailment by the supplier or transporter, the owner/operator shall verbally inform the Executive Secretary of the curtailment and use of coal. The owner/operator shall also document such incidents in a report for each month in which they occur. The Executive Secretary shall also be notified of the end of the curtailment within 48 hours.

9. Fugitive emissions from the coal piles and any unpaved roads associated with these sources shall be minimized by water spraying as dry conditions warrant or as determined necessary by the Executive Secretary.

10. When coal is burned, the following conditions shall apply:

    A. The baghouses on both boilers shall be stack tested for PM_{10} and NO_x every 3 years.

    B. All boiler flue gases shall pass through a baghouse.

11. The same consignments of coal shall be used at the refinery steam plant as are used at the main power plant. If the refinery steam plant uses a different consignment of coal in the future, that coal shall be subject to the same testing requirements as coal for the main power plant. The testing requirements are as follows:

  A. Coal increments will be collected using ASTM 2234, Type I Conditions A, B, C and systematic spacing. Fuel lot size is defined as the weight of fuel consumed during three operational hours.

  B. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D Methods 2013, 3177, 3173, and 2015.

  C. The owner/operator shall submit monthly reports to the Executive Secretary of sulfur input to the boilers. The reports shall include sulfur content, gross calorific value, and moisture content of each gross coal sample; the gross calorific value of all coal and gas; the total amount of coal and gas burned; and the running annual average sulfur input calculated at the end of each month of operation.

12. The Executive Secretary shall be notified when startup with coal burning capability occurs as an initial compliance inspection is required.

13. Annual emissions for this source (the entire refinery) are hereby established at 51.9 tons/yr for PM_{10}, 162.6 tons/yr for SO_2 and 121.0 tons/yr for NO_x.

2.2.Z Kennecott Utah Copper, Utah Power Plant, Magna

1. The approved installations shall consist of only the following emissions points:

   A. Boiler no.1 (490 mmBtu/hr)
   B. Boiler no.2 (490 mmBtu/hr)
   C. Boiler no.3 (490 mmBtu/hr)
   D. Boiler no.4 (910 mmBtu/hr)
   E. Other associated equipment

2. During the period from November 1 to the last day in February, inclusive, the following conditions shall apply:

   A. The four boilers shall use only natural gas as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant may then burn coal, only for the duration of the curtailment. The Executive Secretary shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.

   B. The following limits on fuel usage shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

      1) 40 million cubic feet per day of natural gas

      2) 1370 tons per day of coal, only during curtailment of natural gas supply

   C. Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

      1) For each of boilers no. 1, 2, & 3:

         a) PM_{10} - 0.004 grain/dscf (68°F, 29.92 in Hg)

         b) NO_x - 173 lb/hr
            336 ppmdv (measured at 3% oxygen)

      2) For boiler no. 4:

         a) PM_{10} - 0.004 grain/dscf (68°F, 29.92 in Hg)

b) NO_x - 317 lb/hr
336 ppmdv (measured at 3% oxygen)

D. During a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 15.9 lb/hr
- 0.029 grain/dscf (68°F, 29.92 in Hg)

b) NO_x - 278 lb/hr
- 597 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:

a) PM_{10} - 36.4 lb/hr
- 0.029 grain/dscf (68°F, 29.92 in Hg)

b) NO_x - 637 lb/hr
- 597 ppmdv (measured at 3% oxygen)

E. Owner/operator shall provide monthly reports to the Executive Secretary showing daily total emission estimates based upon boiler usage, fuel consumption and previously available results of stack tests.

3. During each annual period from March 1 to October 31, inclusive, the following conditions shall apply:

A. The owner/operator shall use coal, natural gas, oils that meet all the specifications of 40 CFR 266.40(e) and contains less than 1000 ppm total halogens, and/or number 2 fuel oil or lighter in the boilers.

B. The following limit on fuel usage shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

50,400 million Btu per day of heat input

C. Emissions to the atmosphere from each emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

   a) PM_{10} - 15.9 lb/hr
      - 0.029 grain/dscf
        (68°F, 29.92 in Hg)

   b) NO_x - 562 lb/hr
      - 1208 ppmdv
        (measured at 3% oxygen)

2) For boiler no. 4:

   a) PM_{10} - 36.4 lb/hr
      - 0.029 grain/dscf
        (68°F, 29.92 in Hg)

   b) NO_x - 796 lb/hr
      - 746 ppmdv (measured at 3% oxygen)

4. Stack testing to show compliance with the above emission limitations shall be performed for all four boilers and the following air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A for more details), and as directed by the Executive Secretary:

		Method	Retest every
A.	NO_x	7	1 year
B.	PM_{10}	201/201a	1 year

The heat input during all compliance testing shall be no less than 90% of the design rate, which is 441 MMBTU/hr for boilers 1, 2, and 3, and 819 MMBTU/hr for boiler 4.

5. Visible emissions from the boiler stacks indicated below shall not exceed the associated opacity on a 6-minute average, as measured by a CEM:

Source	Natural Gas Fuel	Coal Fuel
Boilers #1, #2 and #3	10% Opacity	20% Opacity
Boiler #4	10% Opacity	*

* Prior to installation of the low-NO_x burners visible emissions from the #4 boiler stack shall not exceed 40% opacity based upon Method 9

After installation of the low-NO_x burners visible emissions from the #4 boiler stack shall not exceed 20% opacity based upon Method 9, provided that:

A. The opacity limit is applicable as defined in 40 CFR 60.11(c);

B. Kennecott fails to submit a petition as described in 40 CFR 60.11(e)(6);

C. Kennecott fails to make the demonstration required in 40 CFR 60.11(e)(7) and (8).

6. The sulfur content of any fuel burned shall not exceed 0.52 lb of sulfur per million Btu (annual running average), nor shall any one test exceed 0.66 lb of sulfur per million Btu.

A. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or C and systematic spacing. Fuel lot size is defined as the weight of fuel consumed during three operational hours.

B. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D methods 2013, 3177, 3173, and 2015.

C. Failure of the owner/operator to measure at least 95% of the required increments in any one month shall constitute a violation of this provision.

D. The owner/operator shall submit monthly reports of sulfur input to the boilers. The reports shall include sulfur content, gross calorific value and moisture content of each gross coal sample; the gross calorific value of all coal and gas; the total amount of coal and gas burned; and the running annual average sulfur input calculated at the end of each month of operation.

7. Natural gas consumption shall be determined by metering the gas as it is fed into the boilers with gauges, which shall be installed if necessary. Records shall be kept on a daily basis. Coal consumption shall be determined by examination of purchase records and the use of a weigh conveyor which feeds each boiler.

8. Annual emissions for this source (the entire power plant) are hereby established at 257 tons/yr for PM_{10}, 6219 tons/yr for SO_2, and 5085 tons/yr for NO_x.

2.2.AA Kennecott - Barneys Canyon Operations

1. The installations shall consist of only the following equipment located at the site:

   A. Crushers
   B. Screens
   C. Conveyors
   D. Haul Trucks
   E. Loaders
   F. Graders
   G. Bulldozers
   H. Drills
   I. Cement Silo
   J. Propane Heaters
   K. Mercury Retorts
   L. Water Trucks
   M. Lab Equipment
   N. Utility Vehicles
   O. Cranes
   P. Forklifts
   Q. Light Plants
   R. Induction Furnace
   S. Carbon Regeneration Kiln
   T. Various Small Engine Powered Mobile Equipment

2. Ore throughput shall not exceed 2,400,000 tons per 12-month period without prior approval in accordance with Section 3.1, UACR. Compliance with the throughput limitation shall be determined on a rolling-monthly total. On the first day of each new month, a new 12-month total shall be calculated using the previous 12 months. Records of throughput shall be kept for all periods when the plant is in operation. Records of throughput shall be made available to the Executive Secretary of the Utah Air Conservation Committee upon request, and shall include a period of two years ending with the date of the request. Throughput shall be determined by the use of weight conveyors and a daily operations log. The daily throughput shall be entered in the operations log every day.

3. Visible emissions from the following emission points shall not exceed the following values:

   A. Crushers - 10% opacity
   B. Screens - 10% opacity
   C. Conveyor transfer points - 10% opacity
   D. Cement silo - 10% opacity
   E. All fume hoods - 5% opacity
   F. All propane heaters - 5% opacity
   G. Unpaved roads, front-end loading, truck dumping,

stockpiles, blasting, bulldozing, operations area - minimize emissions

H. Drilling - 10% opacity
I. Atomic absorption laboratory - 5% opacity
J. Cyanide mixing tank - 5% opacity
K. Carbon acid wash - 5% opacity
L. Carbon stripping - 5% opacity
M. Carbon regeneration - 5% opacity
N. Mercury retort - 5% opacity
O. Ammonium Nitrate Storage Silos - 10% Opacity
P. All other points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

4. The height of the mine waste dump lift shall not exceed 500 feet. The owner/operator shall provide to the Executive Secretary for approval a method to keep opacity on active waste slopes at less than 10% opacity. Average opacity emissions from the active waste dump push slopes shall not exceed 10%. To insure that 10% opacity is not exceeded, the waste dump slopes shall be monitored for opacity level during dumping activity. If the 10% opacity limitation cannot be maintained by applying additional control measures, dumping activity shall be relocated to an alternative site where 10% opacity can be maintained. Relocation shall be performed within six (6) operating hours of an exceedance of the 10% opacity limit. Opacity observations of emissions from these sources shall be conducted in accordance with 40 CFR 60, Appendix A. Method 9.

5. The ore and waste haul roads shall be treated with magnesium chloride solution and shall be treated in accordance with the fugitive dust control plan appended to this subsection. Modifications of the fugitive dust control plan may be made with consent with the Executive Secretary without processing a new approval order. The fugitive dust control plan shall be accepted by the Executive Secretary prior to issuance of the approval order.

6. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

A. All crushers
B. All screens
C. All conveyor transfer points

The sprays shall operate whenever dry conditions warrant and to the extent necessary to keep equipment operation within an opacity limitation of 10%.

7. The following operating parameters shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. Bulldozing total hours of operation for all bulldozers used per 12-month period - 20,175 hours

   B. Length of Melco pit haul roads - 5.0 miles

   C. Length of Barneys pit haul roads - 1.4 miles

   D. Length of waste dump haul roads - 1.0 miles

   E. Maximum gross weight of all haul trucks - 162 tons

   F. Minimum gross weight of all haul trucks - 85 tons

   G. Ore truck trips per 12-month period - 90,000

   H. Truck trips to mine dumps per 12-month period - 220,000

   Compliance with the limitations on the bulldozing hours of operation, the ore truck trips, and the truck trips to the mine dumps shall be determined on a rolling-monthly total. On the first day of each month a new 12-month total shall be calculated using the previous 12 months.

   Records of hours of operation on the bulldozing, the ore truck trips and the truck trips to the mine dump shall be kept for all periods when the plant is in operation. The records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. The bulldozing hours of operation shall be determined by examination of an operations log in which shall be recorded daily the bulldozing hours of operation. The entries shall include all hours of all machines operated.

   The number of truck trips shall be determined by examination of an operations log in which trips shall be recorded daily. The entries shall included all truck trips to each respective destination.

8. The drills used for drilling the blast holes shall be equipped with small fabric filter units mounted on the

drill carriage or otherwise connected to the drill or wet drilling shall be performed. The filter units shall be operative whenever dry air drilling is taking place.

9. The cement silo shall be equipped with a fabric type bin vent control unit. All displaced air generated from filling the silo with cement shall pass through the filter unit before being vented to the atmosphere.

10. All ore storage piles shall be sprayed with water or chemical dust suppressants as dry conditions warrant or as determined necessary by the Executive Secretary.

11. The pH of the leaching solution shall be no less than 10 at all times. The pH shall be continuously monitored. The readout for each leaching pile shall be located where an inspector can safely read the pH at any time. Continuous recording of the pH on strip charts or another similar recording device is required. The continuous monitoring system shall be subject to Section 4.6.4, UACR, which deals with monitoring reports. All continuous monitoring data shall be kept by the source for a minimum period of two years after the date on which emissions occurred and shall be made available to the Executive Secretary upon request.

12. The sulfur content of diesel fuel oil burned in the equipment engines shall not exceed 0.21 pound of sulfur (.026 pound of sulfur after December 1993) per million BTU heat input as determined by ASTM Method D-4294-89. (This represents 0.4% sulfur (less than 0.05% after December 1993) by weight in the fuel oil, 137,000 btu/gal, and 7.05 lb/gal). The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall not exceed 1,500,000 gal/yr. Fuel consumption shall be determined by mine records of oil purchased.

13. For sources which are subject to NSPS, visible emission observations which are performed during the initial compliance inspection shall consist of 30 observations of six minutes each in accordance with 40 CFR 60, Appendix A, Method 9. It is the responsibility of the owner/operator of the source(s) to supply these observations to the Executive Secretary. Emission points which are subject to NSPS shall include the following:

A. All ore crushers
B. All ore classifying screens
C. All conveyor transfer points

14. The moisture content of the ore material shall be maintained at a value of no less than 4% by weight during handling operations. The moisture content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

15. Annual emissions for this source (the entire plant site) are currently calculated at 160 tons/yr for PM_{10}, 23 tons/yr for SO_2, 216 tons/yr for NO_x.

2.2.BB Kennecott Utah Copper - Bonneville Concentrator & Tailings Pond, Magna

2.2.BB.A Bonneville Concentrator

1. The installation shall consist of only the following emission points:

   A. Primary crusher
   B. Syntron feeder
   C. Secondary crusher
   D. Secondary crusher - Screen and conveyor
   E. Scissor belt
   F. Tertiary crusher
   G. Tertiary discharge
   H. Fine ore transfer and storage
   I. Fine ore storage (3 units)
   J. Fine ore feeder floor discharge (4 units)
   K. Other associated equipment

2. Emissions to the atmosphere from the indicated emission point(s) shall not exceed the following rates and concentrations:

   A. Primary crusher

      PM_{10} 6.2 lbs/hr 0.016 grains/dscf

   B. Syntron feeder

      PM_{10} 2.4 lbs/hr 0.016 grains/dscf

   C. Secondary crusher

      PM_{10} 5.5 lbs/hr 0.016 grains/dscf

   D. Secondary crusher - Screen and conveyor

      PM_{10} 4.8 lbs/hr 0.016 grains/dscf

   E. Scissor belt

      PM_{10} 0.6 lbs/hr 0.016 grains/dscf

   F. Tertiary crusher

      PM_{10} 4.8 lbs/hr 0.016 grains/dscf

   G. Tertiary discharge

PM_{10}	4.8 lbs/hr	0.016 grains/dscf

H. Fine ore transfer and storage

PM_{10}	2.8 lbs/hr	0.016 grains/dscf

I. Fine ore storage (3 units)

PM_{10}	2.1 lbs/hr per unit	0.016 grains/dscf

J. Fine ore feeder floor discharge (4 units)

PM_{10}	1.7 lbs/hr per unit	0.016 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A for more details), and as directed by the Executive Secretary:

		Method	Test Every
A. Primary crusher	PM_{10}	201/201a	1 year
B. Syntron feeder	PM_{10}	201/201a	3 years
C. Secondary crusher	PM_{10}	201/201a	3 years
D. Secondary crusher - Screen & conveyor	PM_{10}	201/201a	3 years
E. Scissor belt	PM_{10}	201/201a	3 years
F. Tertiary crusher	PM_{10}	201/201a	3 years
G. Tertiary discharge	PM_{10}	201/201a	3 years
H. Fine ore transfer and storage	PM_{10}	201/201a	Test if directed

I. Fine ore storage (3 units)
PM_{10} 201/201a Test if directed

J. Fine ore feeder floor discharge (4 units)
PM_{10} 201/201a Test if directed

4. Visible emissions from any point emission source associated with the installation or control facilities shall not exceed 10% opacity. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

5. Ore reporting to the outdoor storage pile(s) shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary.

6. The total base acreage of the outdoor storage pile(s) shall not exceed 6.0 acres.

7. The ore throughput shall not exceed the following limits:

1,700	tons per hour
12,500,000	tons per year

Compliance with the annual limitations shall be determined on a rolling monthly total. Based on the first day of each month a new 12-month total shall be calculated using the previous 12 months. Records of throughput shall be kept for all periods when the plant is in operation. Records of throughput shall be made available to the Executive Secretary or his representative upon request and shall include a period of two years ending with the date of the request. Throughput shall be determined by plant records. The records shall be kept on a daily basis.

8. Annual emissions for this source (the entire plant) are hereby established at 234 tons/yr for PM_{10}.

2.2.BB.B Kennecott Tailings Pond

1. The new peripheral discharge system shall contain four segments, each capable of providing 7,500 gallons per minute (gpm) of tailings flow. Each segment shall be attached to the existing peripheral discharge line by a total of five valves per segment. Each valve shall be capable of delivering the entire 7,500 gpm flow to the existing peripheral discharge system, along 1,500 linear feet of pipeline. The new peripheral discharge system shall consist of an eastern and western half, with each half capable of delivering 15,000 gpm. The system shall be designed for simultaneous or independent operation. A 48 inch point discharge line shall be installed. The peripheral discharge system shall have the capacity to deliver at least 30,000 gallons per minute.

2. A complete sequence through a given segment shall be considered to contain ten successive areas. The cycle time required for complete rotation of a given segment shall be four days (i.e., all interior beach areas of the pond to be wetted in four days).

3. At least 48 hours prior to each wind event that is predicted (wind gusts forecasted to exceed 25 miles per hour (mph) for more than one hour, as measured by Kennecott's station on top of the tailings pond) or for other events determined necessary by Kennecott or the Executive Secretary, Utah Air Conservation Committee (UACC), the tailings shall be redirected to those tailings pond areas most susceptible to wind erosion.

4. Magnesium chloride or other stabilization methods approved by the Executive Secretary, shall normally be reapplied to the top, middle, and lower perimeter unpaved roadways no later than May 30 of each calendar year and reapplied, as necessary, to minimize these sources of air pollution throughout the year.

    A. If the roadways become a source of significant emissions, due to future dry, spring weather conditions, the application of magnesium chloride following wet, winter months shall be done prior to May 30, the date is to be negotiated between Kennecott and the Executive Secretary, UACC.

    B. Fugitive road dust generated by: 1) dike raising construction, 2) usage of unpaved roads by traffic prior to the required reapplication, and 3) the decrease in effectiveness of magnesium chloride, shall be stabilized by water sprays or other methods on an as-needed basis or as determined necessary and be approved by the Executive Secretary, UACC.

5. Between February 15 and November 15 of each calendar year, Kennecott shall inspect the interior surface area, unpaved roads, and exterior dike area at least every two weeks and daily when 48 hours before a wind event, wind gusts are forecasted to exceed 25 mph for more than one hour as measured by Kennecott's station on top of the tailings pond.

6. The tailings distribution system shall be operated to maximize surface wetness. No more than 50 contiguous acres or more than 5 percent of the total tailings area shall be permitted to be dry at any time, unless those areas are stabilized by vegetation or other methods of fugitive dust control approved by the Executive Secretary, UACC. Kennecott shall routinely conduct dryness grid inspections monthly. The grid inspections may be done concurrently with inspections required in condition 5 above. If it is determined by Kennecott or the Executive Secretary, UACC that the total surface dryness is greater than 5 percent or at the request of the Executive Secretary, a dryness grid inspection schedule shall be immediately initiated by Kennecott resulting in inspections being conducted twice every five working days and reported to the Executive Secretary, UACC within 24 hours of the determination, until Kennecott measures a total surface dryness content of less than or equal to 5 percent. If Kennecott or the Executive Secretary, UACC determines that the dryness percentage is exceeded, Kennecott shall meet with the Executive Secretary, or his staff, to discuss additional or modified fugitive dust controls/operational practices and an implementation schedule for such with five working days after verbal notification by either party.

7. Exterior tailings pond areas determined by Kennecott or the Executive Secretary, UACC to be sources of excessive fugitive dust shall be stabilized through vegetation cover or other approved methods.

8. Kennecott shall schedule dike raising and associated peripheral pipe deactivation in an efficient manner so as to minimize fugitive emissions and peripheral discharge pipeline downtime. Fugitive dust generated from disturbed areas created by dike raising, shall be stabilized by water sprays or other methods approved by the Executive Secretary, UACC. The dike raising schedule for the southern-half of the tailings pond between April 1 and November 15 shall be as follows:

   A. No more than 3,000 feet of contiguous peripheral discharge pipeline may be deactivated for longer than seven working days.

   B. No more than 2,500 feet of contiguous peripheral discharge pipeline may be deactivated for longer than 12 working days.

9. For interior areas that may create dust problems near the Arthur pump station, dust controls shall be implemented as follows:

   A. The fresh water feed line shall be used to floor the remaining Arthur impoundments on an as-needed basis.

   B. The peripheral discharge pipeline shall be used to keep beach areas wet.

   C. Other controls may be requested as determined necessary by Kennecott or the Executive Secretary, UACC.

10. Alert monitoring/bureau notification.

   A. Kennecott shall comply with the following tailings monitoring/bureau notification procedures:

      1. Alert monitoring/bureau notification
         a. DAILY BASIS

            Watch the forecast for northwest winds impacting tailings area. If high winds (25 mph or greater as measured by Kennecott's station on top of the tailings pond) are forecasted within 48 hours:

(1) Contact the Bureau of Air Quality (BAQ) and coordinate the measurement of wind data.

(2) Update forecast on a 24 hour basis.

b. ALERT BASIS

If a front is near or the forecast is for wind direction from west through north at more than 25 mph wind speed for more than one hour, the procedures listed below shall be followed:

(1) Alert the BAQ immediately.

(2) Continue surveillance and coordination.

11. Fugitive dust maintenance program reporting procedures:

A. On a quarterly basis, Kennecott shall summarize the following for the Executive Secretary, UACC:

1. Documentation of the average monthly moisture content of the tailings surface area, and wind direction and speed data for days that northwesterly winds exceeded 25 mph for a period of one hour or greater during which no precipitation occurred.

2. Documentation showing tailings pond control implementations and maintenance procedures used.

3. Quarterly reports shall be submitted to the Executive Secretary, UACC within 30 days following the end of each calendar quarter.

12. Kennecott shall comply with Section 3.2, Utah Air Conservation Regulations.

13. Kennecott shall continue to give periodic updates, as requested by the Executive Secretary to the

UACC, concerning the status of the tailings pond on an invitational basis.

14. When it is determined by Kennecott or the Executive Secretary, UACC that additional tailings dust control beyond the above should be considered or tailings pond operational problems are occurring, Kennecott shall meet with the Executive Secretary, or his staff, to discuss proposed fugitive dust controls and implementation schedule within five working days after verbal notification by either party.

15. Dust control plans in the event of a temporary or permanent shutdown should occur as follows:

    A. Kennecott shall follow interim dust control procedures as proposed in the December 16, 1987, letter for temporary shutdowns.

    B. Kennecott shall follow the dust control procedures for closure as proposed in the July 1, 1988, Final Reclamation Plan or modified plan approved by the Executive Secretary, UACC in concurrence with the Division of Oil, Gas and Mining and other applicable state agencies.

2.2.CC LDS Hospital

1. The installations shall consist of the following equipment located at the site:

A.	Boilers No. 1 and 2	(22,000 lb steam/hr each)
	Associated Baghouses	(18,000 ACFM each)
B.	Boiler No. 3	(43,000 lb steam/hr)
	Associated Baghouse	(40,430 ACFM)

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

For "Summer-time" coal fired operation, during the period from March 1st through October 31st:

A. Boiler No. 1

1.	PM_{10}	0.88 lbs/hr	.012 grains/dscf
2.	SO_2	36.0 lbs/hr	420 ppmdv
3.	NO_x	16.8 lbs/hr	274 ppmdv

B. Boiler No. 2

1.	PM_{10}	0.88 lbs/hr	.012 grains/dscf
2.	SO_2	36.0 lbs/hr	420 ppmdv
3.	NO_x	16.8 lbs/hr	274 ppmdv

C. Boiler No. 3

1.	PM_{10}	0.99 lbs/hr	.006 grains/dscf
2.	SO_2	70.4 lbs/hr	366 ppmdv
3.	NO_x	17.6 lbs/hr	128 ppmdv

For any combination of boilers the arithmetic sum of the individual boiler mass limitations shall apply.

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, and Paragraph 2.1.A:

		Method	Test Date
Boilers no. 1 & 2 & 3			
A.	PM_{10}	201/201a	1 year
B.	SO_2	6	Test If Directed

C. NO_x 7 Test If Directed

4. The owner/operator shall fire natural gas in the boilers from November 1st through February 28th each season beginning in the winter season of 1992-1993. The remainder of the year coal may be fired at the discretion of the source management.

The sulfur content of any coal or any mixture of coals burned shall not exceed 0.60 pound of sulfur per million BTU heat input as determined by ASTM Method D-3177-75. The sulfur content shall be tested if directed by the Executive Secretary. Coal consumption shall not exceed 10,467 tons/yr. Coal consumption shall be determined by maintaining sales receipts, and by monitoring the daily input of coal. Compliance with the annual limitations shall be determined for each summer season. On the first day of each March a new seasonal record shall begin, and shall continue through October 31st. Records of fuel consumption (both coal and gas) shall be kept for all periods when the plant is in operation. Records of consumption shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

5. Particulate captured in the control facilities shall be conveyed to the existing ash handling equipment where it shall be mixed with water to minimize emissions during disposal of the collected ash.

6. Annual emissions for this source (the entire plant) are hereby established at 6.18 tons/yr for PM_{10}, 156.9 tons/yr for SO_2, 74.2 tons/yr for NO_x.

2.2.DD LDS Welfare Square

1. The installations shall consist of only the following equipment plus any equipment not capable of producing air contaminants:

   A. Modified Keeler Boiler (Natural Gas Fired) 17,000 lb steam/hr

   B. Cleaver Brooks Boiler (Natural Gas) 150 HP

   C. Superior Boiler (Natural Gas) 250 HP

   D. 16,700 ACFM Baghouse controlling the Grain Elevator

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations and testing shall be as follows:

   A. Grain Elevator Baghouse

PM_{10}	1.20 lbs/hr	.010 grains/dscf

   B. Use 201/201a in accordance with paragraph 2.1.A and retest every 3 years.

3. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. Combined heat input (for all three boilers) shall not exceed 20,000 MMBTU per year.

   B. Annual throughput of grain shall not exceed one million tons.

   Records or operations logs of amounts of coal used and hours of operation shall be kept to determine compliance with the above limitations.

4. The owner/operator shall use only natural gas as primary fuel in the three boilers. The (large) Keeler boiler will be modified to burn natural gas or #2 fuel oil or better as back up fuel. Back up fuel oil shall not exceed 10% of the annual BTU energy required. The Keeler boiler will be permitted to burn coal if and only if both natural gas and fuel oil become unavailable. In such a case the owner/operator must notify the Executive Secretary within 48 hours. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of any fuel oil burned shall not exceed

0.45 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4294-89). The sulfur content shall be tested if directed by the Executive Secretary.

5. Annual emissions for this source (the entire plant including fugitive emissions from all grain handling operations are hereby established at 11.2 tons/yr for PM_{10}, 0.47 tons/yr for SO_2, 1.37 tons/yr for NO_x.

2.2.EE Monroc - Kearns (Cottonwood closed)

1. The installations shall consist of only the following equipment:

   A. 7 - silos concrete/flyash with baghouse bin vent type controls
   B. Concrete Batch Plant, 5 cu-yd batch
   C. Aggregate Wash Plant
   D. 3 - Cone Crushers
   E. 1 - Jaw Crushers
   F. 1 - single deck screen
   G. 1 - double deck screen
   I. Associated conveyors
   J. 2 Front-end loaders & water truck
   K. Mixer and aggregate haul trucks

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 350 ton/hr washed aggregate
   B. 300,000 ton/yr washed aggregate
   C. 80,000 cu-yd/yr concrete
   D. 300,000 ton/yr unwashed aggregate products
   E. 8 hours/day
   F. 2,000 hours/yr

3. The silos shall be pneumatically loaded with cement or flyash. The displaced air from the silos generated during filling shall be passed through a baghouse. The flow rate through the baghouse shall not exceed 1100 ACFM. The pneumatic conveyor transfer pressure shall not exceed 15.0 psig.

4. The baghouse flow rate shall be measured at the request of the Executive Secretary. The method shall be 40 CFR 60, Appendix A, Method 2.

5. The pressure of the pneumatic conveyors shall be continuously monitored with equipment located such that an operator or inspector can at any time safely read the output (continuous recording not required). The reading shall be accurate to within plus or minus 1.5 psig. The instrument shall be calibrated against a primary standard at least once every 180 days. The primary standard shall be specified by the Executive Secretary.

6. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

A. All crushers
B. All screens
C. All conveyor transfer points

The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

7. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the products, washed aggregate 3% and road base 10%, shall not exceed the indicated percent (%) by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

8. Records of consumption/production or throughput shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

9. Annual emissions for this source (the entire plant) are hereby established at 21.4 tons/yr for PM_{10}, 0.6 tons/yr for SO_2, 7.6 tons/yr for NO_x.

2.2.FF Monroc, Inc - Beck Street

1. The installations shall consist of only the following equipment:

   A. H & B asphalt plant
   B. Specialty sand plant
   C. Ballast plant
   D. Cone crusher
   E. Grizzly
   F. Screens
   G. Concrete batch plant
   H. Dozers (1), front-end loaders (6)
   I. Dragline & backhoe
   J. Conveyors and stackers
   K. Diesel engine equipment
   L. Any equipment or facilities which are not capable of producing air contaminants

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Asphalt plant stack

PM_{10}	4.22 lbs/hr	0.024 grains/dscf

   B. Specialty sands stack

PM_{10}	1.09 lbs/hr	0.016 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

	Method	Retest Every
A. Stack #2		
PM_{10}	201/201a	3 year
B. Stack #3		
PM_{10}	201/201a	3 years

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. 190 tons asphalt/hr
B. 150,000 tons asphalt/yr
C. 3000 hours/yr
D. 300 ton aggregate/hr
E. 600,000 ton aggregate/yr
F. 300 ton ballast/hr
G. 500,000 ton ballast/yr

Asphalt ballast and aggregate production shall be determined by examination of weigh scale records. The records shall be kept on a daily basis when the plant is operated. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

5. The paved haul road shall be cleaned by a street vacuum equipped with a baghouse or by water flooding as necessary to minimize fugitive dust.

6. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. The total acreage of the storage piles shall not exceed 100 acres.

7. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

8. The moisture content of the aggregate material shall be maintained at a value of no less than 4.0% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

9. The asphalt plant baghouse flow rate shall be measured at the request of the Executive Secretary. The method shall be 40 CFR 60, Appendix A, Method 2.

10. The sulfur content of any coal or coal blend fired shall not exceed 0.6% by weight without prior approval in accordance with Section 3.1, UACR. The sulfur content of the coal shall be determined if directed by the Executive Secretary using the appropriate ASTM

method.

11. Annual emissions for this source (the entire pit, aggregate plant and ballast plant) are hereby established at 69.5 tons/yr for PM_{10}, 8.0 tons/yr for SO_2, 17.2 tons/yr for NO_x.

.2.GG Morton Salt Company - 8800 West North Temple

1. The installations shall consist of only the following equipment:

   A. Stack #2, Salt Dryer Scrubber, NG Fired
   B. Stack #3, Silo Scrubber
   C. Stack #4, Pellet Forming Scrubber
   D. Stack #5, Block Plant Scrubber
   E. Stack #6, Mill Processing Scrubber
   F. Stack #7, Loadout and Bagger

2. Emissions to the atmosphere from the indicated emissions points shall not exceed the following rates and concentrations:

   A. Stack #2, Salt Dryer Scrubber, NG Fired

PM_{10}	4.50 lbs/hr	0.061 grains/dscf

   B. Stack #3, Silo Scrubber

PM_{10}	2.50 lbs/hr	0.0271 grains/dscf

   C. Stack #4, Pellet Forming Scrubber

PM_{10}	2.0	0.019 grains/dscf

   D. Stack #5, Block Plant Scrubber

PM_{10}	1.73 lbs/hr	0.038 grains/dscf

   E. Stack #6, Mill Processing Scrubber

PM_{10}	2.80 lbs/hr	0.012 grains/dscf

   F. Stack #7, Loadout and Bagger

PM_{10}	0.22 lbs/hr	0.016 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60,

Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

		Method	Retest Every
A.	Stack #2		
	PM_{10}	201/201a	3 years
B.	Stack #3		
	PM_{10}	201/201a	3 years
C.	Stack #4		
	PM_{10}	201/201a	3 years
D.	Stack #5		
	PM_{10}	201/201a	3 years
E.	Stack #6		
	PM_{10}	201/201a	2 years

For purposes of this condition SIP approval means approval of the SIP by the UACC.

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. 75 tons/hr (Dryer only)
B. 250,000 tons/yr (Shipped tons)
C.

Dryer Stack	#2	4500 Hr
Silo Stack	#3	7200 Hr
Pellet Stack	#4	7200 Hr
Block Stack	#5	4000 Hr
Mill Stack	#6	7200 Hr
Bulk Stack	#7	7200 Hr

D. 126 mmscf/yr natural gas and propane as back up.

Backup propane fuel shall not exceed 10% of the total plant fuel fired per year. Salt production, hours of operation and fuel consumption shall be determined by plant records. The records shall be kept on a daily basis, hours of operation shall be determined by supervisor monitoring and maintaining an operations log, and fuel consumption shall be determined by Mountain Fuel Company billing records and propane purchase records.

5. The venturi pressure drop obtained during any compliance test on any scrubber shall be maintained as the minimum operating pressure drop until the next compliance demonstration stack test.

   A. The scrubber venturi pressure drop shall be continuously monitored with equipment located such that an inspector can at any time safely read the output. The reading shall be accurate to within plus or minus 0.50 in. W.C.. The instrument shall be calibrated against a "U" tube manometer primary standard least once every 90 days.

6. All unpaved operational roads which are used by mobile equipment shall be sprayed with a brine solution as necessary to reduce fugitive dust.

7. The owner/operator shall use only natural gas and propane as backup fuel during periods of natural gas curtailment. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

8. Annual emissions for this source (the entire plant) are hereby established at 49.1 tons/yr for PM_{10}, 0.9 tons/yr for SO_2, 18.3 tons/yr for NO_x.

2.2.HH Mountain Bell, Offices emergency diesel generators

1. The installations shall consist of only the following equipment:

    A. Eight Detroit Diesel Allison Series 149 Engine-Generator Sets
    B. Uninterruptable power system
    C. Other associated equipment

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

    A. 240,000 Kilowatt-hours per year

    Records of the amount of power generated per year shall be maintained.

3. The sulfur content of diesel fuel oil burned in the equipment engines shall not exceed 0.21 pound of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. (This represents 0.4% sulfur by weight in the fuel oil, 137,000 btu/gal, and 7.05 lb/gal). The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall be determined by company records of oil purchased and be submitted yearly to the Executive Secretary.

4. Annual emissions for this source (the entire plant) are hereby established at 0.31 tons/yr for PM_{10}, 0.46 tons/yr for SO_2, 3.90 tons/yr for NO_x.

.2.II Mountain Fuel Supply Co. (general office)

1. The installations shall consist of only the following equipment:

   A. Five Garrett IE 831-800 natural gas fired turbine generators, four operate & one as standby

   B. One Onan 100 KW emergency generator set

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Each of the Five engines:

NO_x	3.56 lbs/hr	2.54 grams/HP-hr

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, and as directed by the Executive Secretary:

   Each of the five engines:

	Method	Test Date
NO_x	7	Test If Directed

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. The production of 16,600 Megawatt hours of electricity per year.

   Records of the amount of power generated per year shall be maintained.

5. Operation of only four of the five gas turbines, or the equivalent of 2,540 horsepower hours per hour (1,895 kW-hr/hr) shall be permitted at any given time.

6. The owner/operator shall use only natural gas as fuel in the turbine engines.

7. Annual emissions for this source (the entire plant) are hereby established at 2.5 tons/yr for PM_{10}, 1.4 tons/yr for SO_2, 71.1 tons/yr for NO_x.

2.2.JJ Mountain Fuel - 100 South 1078 West

1. The installations shall consist of only the following equipment:

   A. Three Garrett IE 831-800 natural gas fired turbine generators
   B. One Onan 250 KW emergency generator, diesel fired
   C. Two Waukesha VRG330 NG fired compressor engines
   D. One Goder 1220 incinerator

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Each of the three Garrett IE 831-800 engines:

NO_x	3.56 lbs/hr	2.54 grams/HP-hr

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, and as directed by the Executive Secretary:

   A. Each of the three engines:

	Method	Test Date
NO_x	7	Test If Directed

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   The production of 8,300 Megawatt hours of electricity per year

5. Operation of only two of the three gas turbines, or the equivalent of 1,270 horsepower hours per hour (947 Kw-hr/hr) shall be permitted at any given time.

6. The owner/operator shall use only natural gas as fuel in the turbine engines.

7. Annual emissions for this source (the entire plant) are hereby established at 1.12 tons/yr for PM_{10}, 0.40 tons/yr for SO_2, 31.2 tons/yr for NO_x.

2.2.KK Murray City Light & Power

1. The installations shall consist of only the following equipment:

   A. 2,000 kW Fairbanks engine (engine #3), S.N. 950246

   B. 1,045 kW Worthington engine (engine #4), S.N. VO-2676

   C. 1,045 kW Worthington engine (engine #5), S.N. VO-2675

   D. 2,400 kW Nordberg engine (engine #6), S.N. 2012-1072

2. The following production/consumption limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. Power generated total 14,425 MW*hr/yr

   B. Fuel Oil Consumption 150,000 gallons/yr

3. A. This source shall use natural gas as primary fuel in all fuel burning furnaces, ovens and boilers. Number 2 fuel oil or better shall be used only as a pilot fuel or backup fuel to be used during natural gas curtailments and for maintenance firing. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UCAR. Fuel consumption shall be determined by gas meter readings and oil receiving and inventory records.

   B. On the first day of each month a new 12-month rolling total emissions inventory shall be compiled. The inventory shall be based on the previous 12-month rolling total operation and the appropriate emission factors and engine settings for each engine.

   The appropriate emission factors, intake manifold pressure, cylinder exhaust temperatures, and pilot rack settings for each engine shall be established for minimum emissions operation through testing using a portable monitoring system or equivalent. The intake manifold pressure, cylinder exhaust temperatures, and pilot rack settings for each engine shall be used whenever the engine is operated.

If the total NO_x emissions exceeds 200 tpy for the previous 12 months, the source shall submit a report of the emissions to the Executive Secretary within 30 days. Within 90 days the source shall submit to the Executive Secretary for approval a plan with proposed specifications for the installation, calibration, and maintenance of a continuous emissions monitoring system (CEMS) for NO_x. The CEM shall be on line within 12 months following the approval of the plan.

4. Annual emissions for this source (the entire plant) are hereby established at 1.62 tons/yr for PM_{10}, 2.38 tons/yr for SO_2, 250 tons/yr for NO_x.

2.2.LL Ostler Rocky Mountain Refractory Company,

1. The installations shall consist of the following equipment located at the site:

   A. Two Dryers
   B. Two Crushers
   C. Ball Mill
   D. Concrete Screen/Mixer
   E. Cement Silo
   F. Storage Piles
   G. Material Handling Equipment

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Dryer/Crusher Baghouse Vent

PM_{10}	0.54 lbs/hr	0.016 grains/dscf

   B. Ball Mill Baghouse Vent

PM_{10}	1.74 lbs/hr	0.016 grains/dscf

   C. Screen/Mixer Baghouse Vent

PM_{10}	0.14 lbs/hr	0.016 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

		Method	Retest every
A.	Dryer/Crusher		
	PM_{10}	201/201a	5 years
B.	Ball Mill		
	PM_{10}	201/201a	5 years
C.	Screen/Mixer		
	PM_{10}	201/201a	Test if directed

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. Clay/Barite Drying and Crushing

1)	11	tons/hr
2)	45,886	tons/yr
3)	16	hours/day
4)	4,171	hours/yr

B. Ball Mill Grinding

1)	11	tons/hr
2)	45,886	tons/yr
3)	16	hours/day
4)	4,171	hours/yr

C. Concrete Mixing/Screening

1)	6.5	tons/hr
2)	27,000	tons/yr
3)	16	hours/day
4)	4,171	hours/yr

5. The following operating parameter shall be maintained within the indicated ranges:

Dryer baghouse exit temperature greater than 250°F

They shall be monitored with equipment located such that an inspector can at any time safely read the output. The readings shall be accurate to within the following ranges:

Plus or minus 5.0 degrees fahrenheit

6. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

A. Spray bar #1 - A two-nozzle spray located at the top or the inclining bucket elevator #1. The elevator shall be enclosed.

B. Spray bar #2 - A two-nozzle spray located at the transfer area in the loading chute to bucket elevator #3. The feeder chute entrance to the base of the #3 elevator pickup point shall be enclosed.

C. Spray bar #3 - A two-nozzle spray located in the loading chute to the screening area. The screening area shall be enclosed.

D. Spray bars #4 and #5 - One nozzle spray located in each of the discharge hoppers from the screening area.

E. Spray bar #6 - A two nozzle spray located at the transfer point from belt #2 in the transfer chute to the roll crusher #1 The entrance to chute #1 shall be enclosed.

F. Spray bar #7 - A two nozzle spray located in the discharge chute from the roll crusher #1. The roll crusher #1 shall be enclosed.

G. Additional sprays shall be installed at the following locations as determined necessity by the Executive Secretary:

1) Loading chute at belt #1
2) Discharge chute from the screen to belt #2
3) Discharge chute from the jaw crusher to elevator #1

The sprays shall operate to the extent necessary to keep the emissions from the equipment equal to or less than the opacity limitations of 2.1.B

7. The moisture content of the clay/barite shall be maintained at a value of no less than 3.0% by weight. The silt content of the product shall not exceed 10.0% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM methods.

8. The owner/operator shall use only natural gas or propane as a fuel in the dryers. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

9. Annual emissions for this source (the entire plant) are hereby established at 5.8 tons/yr for PM_{10}, and 3.8 tons/yr for NO_x.

2.2.MM Jack B. Parson, - 6000 West 5400 South

1. The installations shall consist of only the following equipment:

   A. Batch plant - McNeilus

   B. Cement bulker - International

   C. One loader - Cat Model 950

   D. 9 Mixers

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 150 cubic yards per hour of concrete

   B. 100,000 cubic yards per year of concrete

   C. 12 hours/day

   D. 2700 hours/yr

   Concrete production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

3. The loader operation road length shall not exceed 300 feet without prior approval in accordance with Section 3.1, UACR. The speed of vehicles on the haul road shall not exceed 5.0 miles per hour without prior approval in accordance with Section 3.1, UACR.

4. The haul road shall be paved and shall be cleaned at least twice a week with a street vacuum equipped with a baghouse or by water flooding.

5. Annual emissions for this source (the entire plant) are hereby established at 4.9 tons/yr for PM_{10}, 0.4 tons/yr for SO_2, 4.6 tons/yr for NO_x.

2.2.NN Jack B. Parson, - 1055 West 500 South

1. The installations shall consist of the following equipment located at the site:

   A. Batch plant - Apeco Spec Master
   B. Cement bulker - International
   C. One loader - Cat Model 950
   D. 8 Mixers

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 100 cubic yards per hour of concrete
   B. 100,000 cubic yards per year of concrete
   C. 12 hours/day
   D. 2700 hours/yr

   Concrete production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

3. The loader operation road length shall not exceed 150 feet without prior approval in accordance with Section 3.1, UACR. The speed of vehicles on the haul road shall not exceed 5.0 miles per hour without prior approval in accordance with Section 3.1, UACR.

4. The haul road shall be paved and shall be cleaned at least twice a week with a street vacuum equipped with a baghouse or by water flooding.

5. Annual emissions source (the entire plant) are hereby established at 6.9 tons/yr for PM_{10}, 0.4 tons/yr for SO_2, 4.6 tons/yr for NO_x.

2.2.00 Phillips 66 Company - Woods Cross

1. The installations shall consist of the following equipment:

   A. (4-1a) Thermal catalytic cracking unit (TCC) furnace
   B. (4-1b) TCC combustion air heater
   C. (4-3) TCC Lift Air Heater / Circulation System
   D. (6-1) Reformer catalytic unit furnace
   E. (6-2) Reformer catalytic unit furnace
   F. (6-3) Prefract.reboiler
   G. (7-1) H.F. alkylation depropanizer reboiler
   H. (7-2) H.F. alkylation regeneration furnace
   I. (8-1) Crude furnace burning fuel gas
   J. (10-2) Solvent deasphalting unit furnace
   K. (11-1) Straight run gas plant depentanizer reboiler
   L. (12-1) Naphtha hydrogen desulfurization furnace
   M. (13-1) Isomerization reactor heater
   N. (45-1) Asphalt mix and storage furnace
   O. (45-2) Asphalt mix and storage furnace
   P. (45-3A,B,C,&D) Asphalt storage heaters
   Q. (45-4A,B,C,D,&E) Asphalt storage heaters
   R. (51-4) #4 Boiler
   S. (51-5) #5 Boiler
   T. (51-6) #6 (CO. Boiler
   U. (51-7) Kiln
   V. (14-1) Diesel desulfurization unit
   W. (17-1) Sulfur Unit Tailgas Incinerator
   X. (9-1) Light cycle oil reactor heater
   Y. (9-2) Light cycle oil stabilizer reboiler
   Z. (4-4a) KVG compressor
   AA. (4-4b) KVG compressor
   AB. (6-4a) SVG compressor
   AC. (6-4b) SVG compressor
   AD. (11-2) Clark compressor
   AE. (66-2) Compressor
   AF. (66-2) Flare
   AG. (66-1) Flare
   AH. (68-1) Flare
   AI. Sulfur Recovery Unit Furnaces

2. The following shall be the basis for the SO_2 emissions limitations:

   A. Emissions Limitations:

   Phillips 66, Woods Cross Refinery's maximum SO_2 emissions to the atmosphere shall not exceed the following:

   1) 4.705 tons per day for all but three days per

month. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed (the difference between the total number and the contribution from the TCC Unit, which is yet to be established...see the note in section D for details) tons/day.

2) 6.656 tons per day for three days per month while running flux crude for the purpose of making asphalt. Of this total, SO_2 emissions from all sources included under the emissions cap shall not exceed (the difference between the total number and the contribution from the TCC Unit, which is yet to be established...see the note in section D for details) tons/day. After September 1, 1992, the making of asphalt shall, if practicable, be restricted during the months of November through February, to only those days for which the State Air Monitoring Center (AMC) measures 24-hour PM_{10} concentrations below 120 $\mu g/m^3$.

The annual emission limitation for SO_2 from all sources shall be 1,762 tons per year. Of this total, the annual SO_2 emissions from all sources included under the emissions cap shall not exceed (the difference between the total number and the contribution from the TCC Unit, which is yet to be established...see the note in section D for details) tons.

B. The following sources shall be included in the SO_2 emissions cap:

	Source	Fuel
1)	(4-3) TCC lift air heater / Circulation System	plant gas
2)	(6-1) Reformer catalytic unit furnace	plant gas
3)	(6-2) Reformer catalytic unit furnace	plant gas
4)	(6-3) Reformer catalytic unit furnace	plant gas
5)	(7-1) H.F. alkylation	

	depropanizer reboiler	plant gas
6)	(7-2) H.F. alkylation regeneration furnace	plant gas
7)	(8-1) Crude furnace	plant gas
8)	(10-2) Solvent deasphalting unit furnace	plant gas
9)	(11-1) Straight run gas plant depentanizer reboiler	plant gas
10)	(12-1) Naphtha hydrogen desulphurization furnace	plant gas
11)	(13-1) Isomerization reactor heater	natural gas
12)	(45-1) Asphalt mix and storage furnace	plant gas
13)	(45-2) Asphalt mix and storage furnace	plant gas
14)	(45-3A,B,C,&D) Asphalt storage heaters	plant gas
15)	(45-4A,B,C,D,&E) Asphalt storage heaters	plant gas
16)	(51-4) #4 Boiler	plant gas
17)	(51-5) #5 Boiler	plant gas
18)	(14-1) Diesel desulf. unit	plant gas
19)	(9-1) Light cycle oil reactor heater	plant gas
20)	(9-2) Light cycle oil stabilizer reboiler	plant gas
21)	(4-4a) KVG compressor	natural gas
22)	(4-4b) KVG compressor	natural gas
23)	(6-4a) SVG compressor	natural gas
24)	(6-4b) SVG compressor	natural gas
25)	(11-2) Clark compressor	natural gas

26) (66-2) Compressor natural gas

27) Sulfur Recovery Unit Furnaces plant gas

C. SO_2 emissions for the emissions cap sources shall be determined by applying the following emission factors to the relevant quantities of fuel combusted. This shall be performed according to the following:

1) Emission Factors for the various fuels shall be as follows:

natural gas - 0.60 lb/mmscf

plant gas - the emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor which will measure the H_2S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

(lb SO_2 / mmscf gas) = (24 hr avg. ppmv H_2S)/10^6 * (64 lb SO_2 / lb mole) * (10^6 scf / mmscf) / (379 scf / lb mole)

fuel oil - the emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

(lb SO_2 / kgal) = (density lb/gal) * (1000 gal/kgal) * (wt.% S)/100 * (64 g SO_2 / 32 g S)

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment. The sulfur content of the fuel oil shall be tested if directed by the Executive Secretary.

2) Fuel Consumption shall be measured as follows:

Natural gas consumption shall be determined by the meter totalizer which measures all natural gas supplied to the plant.

Plant gas consumption shall be metered at the amine treater.

Fuel Oil consumption shall be measured each day by means of leveling gages on all tanks which supply oil to combustion sources.

3) The equations used to determine emissions for the emission cap sources shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Total 24-hour SO_2 emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above SO_2 emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt.% S, recorded for each day any fuel oil is burned), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. **Individual Point Source Limitation:**

SO_2 emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for SO_2 at the following emission limits:

Point Source	lb/hr	tons/yr	ppmv
TCC Unit(s) (4-1a,			

4-1b, 51-6, & 51-7)	(limits to be established through testing...see note)
SRU Tailgas Incinerator	(limits to be established during Section 3.1 review)

The SO_2 from the TCC unit shall be determined by measuring the volume of flue gas from the unit and by using EPA Test Method No. 6 for sulfur analysis.

Note: Several sets of stack tests (January 1991, February '91, and the summer of '91) shall be performed on the TCC to check the SO_2 emissions used in the PM_{10} SIP preparation. All testing shall be accomplished, and the results sent to the Executive Secretary, no later than July 15, 1991. The SO_2 emission limit and the emissions from the TCC Unit that are included in the total SO_2 inventory shall be modified as appropriate using the results of the stack tests. These stack tests shall be audited by the Bureau of Air Quality.

E. Stack testing to determine hourly, daily, and annual compliance for the "non-cap" sources described in number 2 D, above, shall be performed as directed in condition number 5 below, and in accordance with sections 2.1.A and 2.1.M of this Appendix.

F. The following sources shall not be regulated for SO_2 emissions, nor shall they be included in the emission limitation totals herein:

1) (66-2) Flare
2) (66-1) Flare
3) (68-1) Flare

3. The following shall be the basis for NO_x emissions limitations:

A. Emissions Limitations:

Phillips 66, Woods Cross Refinery's maximum NO_x emissions to the atmosphere shall not exceed 2.20 tons per day. Of this total, NO_x emissions from all sources included under the emissions cap shall not exceed 2.20 tons per day. The annual emission limitation for NO_x from all sources shall not exceed 693.0 tons. Of this total, the annual NO_x emissions from all sources included under the emissions cap shall not exceed 693.0 tons.

B. The following sources shall be included in the NO_x emissions cap:

	Source	Fuel
1)	(4-1a) Thermal catalytic cracking unit (TCC) furnace	natural gas
2)	(4-1b) TCC combustion air heater	plant gas
3)	(4-3) TCC lift air heater / Circulation System	plant gas
4)	(6-1) Reformer catalytic unit furnace	plant gas
5)	(6-2) Reformer catalytic unit furnace	plant gas
6)	(6-3) Reformer catalytic unit furnace	plant gas
7)	(7-1) H.F. alkylation depropanizer reboiler	plant gas
8)	(7-2) H.F. alkylation regeneration furnace	plant gas
9)	(8-1) Crude furnace	plant gas
10)	(10-2) Solvent deasphalting unit furnace	plant gas
11)	(11-1) Straight run gas plant depentanizer reboiler	plant gas
12)	(12-1) Naphtha hydrogen desulphurization furnace	plant gas
13)	(13-1) Isomerization reactor heater	natural gas

14)	(45-1) Asphalt mix and storage furnace	plant gas
15)	(45-2) Asphalt mix and storage furnace	plant gas
16)	(45-3A,B,C,&D) Asphalt storage heaters	plant gas
17)	(45-4A,B,C,D,&E) Asphalt storage heaters	plant gas
18)	(51-4) #4 Boiler	plant gas
19)	(51-5) #5 Boiler	plant gas
20)	(51-6) #6 Boiler	plant gas
21)	(51-7) Kiln (breakdowns only)	plant gas
22)	(14-1) Diesel desulf. unit	plant gas
23)	(17-1) Sulfur Unit Tail Gas Incinerator	plant gas
24)	(9-1) Light cycle oil reactor heater	plant gas
25)	(9-2) Light cycle oil stabilizer reboiler	plant gas
26) gas	(4-4a) KVG compressor	natural
27) gas	(4-4b) KVG compressor	natural
28) gas	(6-4a) SVG compressor	natural
29) gas	(6-4b) SVG compressor	natural
30) gas	(11-2) Clark compressor	natural
31) gas	(66-2) Compressor	natural
32)	Sulfur Recovery Unit Furnaces	plant gas

C. NO_x emissions for the Emissions Cap Sources shall be determined by applying various emission factors to the relevant quantities of fuel combusted.

Boilers and Furnaces:

1) Emission Factors for the boilers and furnaces shall be as follows:

natural gas - 140 lb/mmscf
plant gas - 140 lb/mmscf
fuel oil - 120 lb/kgal

Daily natural gas consumption by all boilers and furnaces will be quantified by meters, which shall be installed if necessary, that will differentiate the flow of natural gas to the boilers and furnaces from the flow to the compressors.

Daily plant gas consumption by all boilers and furnaces will be quantified by meters, which shall be installed if necessary, that will differentiate the flow of natural gas to the boilers and furnaces from the flow to the compressors.

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks which supply combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

Compressors:

2) The Emission Factor for natural gas combustion in the compressor drivers shall be 3400 lb/mmscf.

Daily natural gas consumption for the compressor drivers shall be quantified by meters, which shall be installed if necessary, that will differentiate the flow of natural gas to the compressors from the flow to the boilers and furnaces.

The emissions shall then be determined using the following equation:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

3) Total 24-hour NO_x emissions for sources included in the emissions cap shall be calculated by adding the results of the above NO_x equations for plant gas, fuel oil, and natural gas combustion. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. The following sources shall not be regulated for NO_x emissions, nor shall they be included in the emission limitation totals herein:

1) (66-2) Flare
2) (66-1) Flare
3) (68-1) Flare

4. The following shall be the basis for PM_{10} emission limitations:

A. Emissions Limitations:

Phillips 66, Woods Cross Refinery's maximum PM_{10} emissions to the atmosphere shall not exceed 0.441 tons per day. Of this total, PM_{10} emissions from all sources included under the emissions cap shall not exceed 0.021 tons per day. The annual emission limitation for PM_{10} from all sources shall not exceed 160.9 tons. Of this total, the annual PM_{10} emissions from all sources included under the emissions cap shall not exceed 7.60 tons.

B. The following sources shall be included in the PM_{10} emissions cap:

	Source	Fuel
1)	(4-1a) Thermal catalytic cracking unit (TCC) furnace gas	natural
2)	(4-1b) TCC combustion air heater	plant gas
3)	(6-1) Reformer catalytic unit furnace	plant gas
4)	(6-2) Reformer catalytic unit furnace	plant gas
5)	(6-3) Reformer catalytic unit furnace	plant gas
6)	(7-1) H.F. alkylation depropanizer reboiler	plant gas
7)	(7-2) H.F. alkylation regeneration furnace	plant gas
8)	(8-1) Crude furnace	plant gas
9)	(10-2) Solvent deasphalting unit furnace	plant gas
10)	(11-1) Straight run gas plant depentanizer reboiler	plant gas
11)	(12-1) Naphtha hydrogen desulphurization furnace	plant gas
12)	(13-1) Isomerization reactor heater gas	natural
13)	(45-1) Asphalt mix and storage furnace	plant gas
14)	(45-2) Asphalt mix and storage furnace	plant gas
15)	(45-3A,B,C,&D) Asphalt storage heaters	plant gas
16)	(45-4A,B,C,D,&E) Asphalt storage heaters	plant gas
17)	(51-4) #4 Boiler	plant gas

18)	(51-5) #5 Boiler	plant gas
19)	(51-6) #6 Boiler	plant gas
20)	(51-7) Kiln (breakdowns only)	plant gas
21)	(14-1) Diesel desulf. unit	plant gas
22)	(17-1) Sulfur Unit Tail Gas	plant gas
23)	(9-1) Light cycle oil reactor heater	plant gas
24)	(9-2) Light cycle oil stabilizer reboiler	plant gas
25)	Sulfur Recovery Unit Furnaces	plant gas

C. PM_{10} emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relevant quantities of fuel combusted in each unit. This shall be performed according to the following:

1) Emission Factors for the combustion sources will be as follows:

natural gas - 5 lb/mmscf

plant gas - 5 lb/mmscf

fuel oil - the PM_{10} emission factor for fuel oil combustion shall be determined based on the H_2S content of the fuel oil as follows:

PM_{10} (lb/kgal) = (10 * wt.% S) + 3

2) Daily natural gas consumption for each cap source will be determined by the meter(s) which measure the total amount of natural gas supplied to the emission cap sources.

Daily plant gas consumption for each cap source will be determined by the meter(s) which measure the total amount of natural gas supplied to the emission cap sources.

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks which supply fuel oil to combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

3) The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/mmscf) * Natural Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/mmscf) * Plant Gas Consumption (mmscf/24 hrs) / (2,000 lb/ton)

Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

4) Total 24-hour PM_{10} emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above PM_{10} emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt.% S), and the calculated emissions. See section 2.1.M Petroleum Refineries of the General Requirements of this Appendix for compliance demonstration details.

D. Individual Point Source Limitation:

PM_{10} emissions limits shall be individually set for each point source not designated as being in the emissions cap. The following Non-Emissions Cap Sources shall be regulated individually for PM_{10} at the following emission limits:

Point Source	lb/hr	gr/dscf	tons/yr
(4-3) TCC Lift Air Heater / Circ. System	35.0	0.480	153.3

E. Stack testing to determine compliance for sources described in Subpart D, above, shall be performed as directed in condition 2.2.A 5 below, and in accordance with Appendix A 2.1.A of this document.

F. The following sources shall not be regulated for PM_{10} emissions, nor shall they be included in the emissions totals herein:

1) (4-4a) KVG compressor
2) (4-4b) KVG compressor
3) (6-4a) SVG compressor
4) (6-4b) SVG compressor
5) (11-2) Clark compressor
6) (66-2) Compressor
7) (66-2) Flare
8) (66-1) Flare
9) (68-1) Flare

5. Stack Testing Requirements:

The following point sources have been required to comply with various emission rates and concentrations in the paragraphs preceding. The following is summary of the testing methods and frequencies appropriate to each point source. The provisions set forth in Appendix A 2.1.A of this document apply to the testing of these listed sources.

A. (4-1a, 4-1b, 51-6, & 51-7) TCC Unit(s)

	Limitations	Test Method	Frequency
SO_2	XXXX lb/hr XXX ppmv	6	If Directed

limits shall be established through stack testing...see the note in section 2. D. for details.

B. (4-3) TCC Lift Air Heater / Circulation System

	Limitations	Test Method	Frequency
PM_{10}	35.0 lb/hr .480 gr/dscf	201/201a	Every 3 yrs.

C. Sulfur Recovery Unit Tail-gas Incinerator

	Limitations	Test Method	Frequency
SO_2	XXXX lb/hr XXX ppmv	CEM	Continuous

limits shall be established through section 3.1 UACR.

6. Annual emissions for this source (the entire plant) are

hereby established at 160.9 tons/yr for PM_{10}, 2,016.0 tons/yr for SO_2 (includes 136 tpy for sulfur plant being down and 118 tons for estimated flare emissions), and 693.0 tons/yr for NO_x.

2.2.PP Pioneer Sand and Gravel

1. The installations shall consist of only the following equipment:

   A. Cedar Rapids 2236 jaw crusher
   B. 45" Eljay fine head cone crusher
   C. Three deck screening plant
   D. 54" Eljay 1130 std cone crusher
   E. Conveyors
   F. 6 loaders

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 350 tons/hr of aggregate
   B. 560,000 tons/yr of aggregate
   C. 8 hours/day
   D. 1600 hours/yr

3. Water spays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the emissions from the equipment equal to or less than the opacity limitations of 2.1.B

4. The moisture content of the aggregate shall be maintained at a value of no less than 4% by weight. The silt content of the product shall not exceed 3.0% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

5. Records of consumption/production or throughput shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive

   Secretary upon request, and shall include a period of two years ending with the date of the request.

6. Annual emissions for this source (the entire plant) are hereby established at 21.8 tons/yr for PM_{10}, 0.9 tons/yr for SO_2, 9.1 tons/yr for NO_x.

2.2.QQ Salt Lake City Asphalt - 1850 North Redwood Road

1. The installations shall consist of only the following equipment:

   A. One Cedarapids asphalt plant model H 50 C
   B. One front end loader
   C. Three aggregate bins

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Asphalt plant baghouse (APBH)

   PM_{10} 4.86 lbs/hr; 0.024 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

   A. Asphalt plant baghouse (APBH)

	Method	Retest every
PM_{10}	201/201a	3 years

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 150 tons/hr of asphalt
   B. 160,000 tons/yr of raw material
   C. 8 hours/day
   D. 1560 hours/yr

5. The moisture content of the raw material shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 15.0% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

6. The owner/operator shall use only natural gas as a fuel in the asphalt plant. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

7. Records of consumption/production or throughput shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

8. Annual emissions for this source (the entire plant) are hereby established at 5.3 tons/yr for PM_{10}, 0.1 tons/yr for SO_2, 5.7 tons/yr for NO_x.

2.2.RR Salt Lake County Asphalt - Welby Pit

1. The installations shall consist of only the following equipment:

   A. 316 Cedar Rapids crusher
   B. 317 Twin jaw crusher
   C. 320 El Jay crusher
   D. Cedar Rapids Asphalt batch plant equipped with a baghouse
   E. Water truck
   F. 7 stock piles
   G. 5 diesel powered mobile construction vehicles

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Asphalt plant baghouse (APBH)

PM_{10}	4.05 lbs/hr	0.024 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

A.	Method	Retest every
PM_{10}	201/201a	5 years

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 1964 Cedar Rapids Crusher (equipment #316)

      1. 100 tons/hr
      2. 84,000 tons/yr
      3. 7 hours/day
      4. 840 hours/yr

   B. 1965 Twin Jaw Crusher (equipment #317)

      1. 100 tons/hr
      2. 84,000 tons/yr
      3. 7 hours/day
      4. 840 hours/yr

   C. 1984 El Jay Crusher (equipment #320)

1. 100 tons/hr
2. 84,000 tons/yr
3. 7 hours/day
4. 840 hours/yr

D. Cedar Rapids Asphalt Batch Plant (equipment #300)

1. 250 tons/hr
2. 300,000 tons/yr
3. 6 hours/day
4. 1200 hours/yr

Asphalt and aggregate production shall be determined by examination of the records of weigh scale readings which shall be maintained at the plant. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

5. The paved roads shall be cleaned at least twice a week with a street vacuum or by water spraying and/or chemical treatment to reduce fugitive dust, or controlled by some other means approved by the Executive Secretary. The disturbed area shall not exceed 65.0 acres without prior approval from the Executive Secretary.

6. The tailings distribution system shall be operated to maximize surface wetness. No more than 50 contiguous acres or more than 5 percent of the tailings area shall be permitted to be dry at any time, unless those areas are stabilized by vegetation or other methods of fugitive dust control approved by the Executive Secretary, UACC. Kennecott shall routinely conduct dryness grid inspections monthly. The grid inspections may be done concurrently with inspections required in condition 5 above. If it is determined by Kennecott or the Executive Secretary, UACC that the total surface dryness is greater than 5 percent or at the request of the Executive Secretary, a dryness grid inspection schedule shall be immediately initiated by Kennecott resulting in inspections being conducted twice every five working days and reported to the Executive Secretary, UACC within 24 hours of the determination, until Kennecott measure a total surface dryness content of less than or equal to 5 percent. If Kennecott or the Executive Secretary, UACC determines that the dryness percentage is exceeded, Kennecott shall meet with the Executive Secretary, or his staff, to discuss additional or modified fugitive dust controls/ operation practices and an implementation schedule for such with five working days after verbal notification

by either party.

7. The total storage pile acreage shall not exceed 5 acres without prior approval from the Executive Secretary. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary.

8. Water spays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

9. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 9.5% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

10. The owner/operator shall use only natural gas as a primary fuel in the asphalt plant. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

11. Annual emissions for this source (the entire plant) are hereby established at 29.3 tons/yr for PM_{10}, 0.6 tons/yr for SO_2, 12.8 tons/yr for NO_x.

2.2.SS Salt Lake Valley Sand and Gravel - point of the mountain

1. The installations shall consist of only the following equipment capable of producing air contaminants located at the site:

Concrete Batch Plant

A. Two 60 ton sand and gravel storage bins
B. One 8 yard McNeilus sand and gravel weigh hopper
C. Two 60 foot long conveyors
D. One 50 foot long conveyor
E. Two cement silos - 110,000 LB capacity each

Main Crushing & Washing Plant

A. Torgensen Scalper 4 x 16
B. Vibranetics Feeder 3 x 10
C. 50 ton sand bin with 2 Syntron Feeders
D. 40" x 20' conveyor
E. 24" x 180' conveyor
F. Power screen 4' x 8'
G. Eljay Cone crusher
H. 36" x 40' conveyor
I. 24" x 60' conveyor
J. 5' x 16' 4 deck Eljay screen equipped with spray bars
K. 44" Eagle sand screw
L. 20" x 50' conveyor
M. 24" x 60' conveyor
N. 24" x 240' conveyor
O. 24" x 200' conveyor
P. 100 ton gravel bin
Q. 24" x 100' stacking conveyor

Kiln Dryer

A. 40 MMBTU/HR kiln dryer (with cyclone and wet scrubber)
B. 30 ton trap
C. 24" x 100' conveyor
D. 20" x 140' conveyor
E. 4' x 10' dry screen enclosed in a building
F. 24" x 100' conveyor
G. 50 ton storage bin
H. 75 ton storage bin

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. 100 tons/hr cone crusher throughput
B. 250,000 tons/yr cone crusher throughput
C. 300 tons/hr total sand and gravel throughput
D. 800,000 tons/yr total sand and gravel throughput
E. 18 hours/day sand and gravel plant operation
F. 4752 hours/yr sand and gravel plant operation
G. 10 tons/hr of finished dryer product
H. 12,000 tons/yr of finished dryer product
I. 9 hours/day dryer plant operation
J. 1200 hours/yr dryer plant operation
K. 80 cubic yards/hr concrete production
L. 160,000 cubic yards/yr concrete production
M. 12 hours/day concrete batch plant operation
N. 2000 hours/yr concrete batch plant operation

3. The silos shall be pneumatically loaded with cement or flyash. The displaced air from the silos generated during filling shall be passed through a baghouse. One baghouse shall be used to control emissions from the two silos. The flow rate through the baghouse shall not exceed 1100 ACFM.

4. The baghouse flow rate shall be measured at the request of the Executive Secretary. The method shall be 40 CFR 60, Appendix A, Method 2.

5. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

A. All crushers
B. All screens
C. All conveyor transfer points prior to the wash plant

The sprays shall operate whenever dry conditions warrant or as necessary such that emissions shall not exceed the opacity limitation.

ıly washed concrete sand shall be fed to the dryer. The dryer screening process shall be enclosed in a building.

7. The owner/operator shall use only number 2 fuel oil or better as a fuel in the dryer kiln. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of any fuel oil burned shall not exceed 0.25 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall not exceed 340.0 kgal/yr. Fuel

consumption shall be determined by examination of vendor sales receipts.

8. Records of consumption/production or throughput shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

9. Annual emissions for this source (the entire plant) are hereby established at 43.9 tons/yr for PM_{10}, 13.9 tons/yr for SO_2, 21.4 tons/yr for NO_x.

?.2.TT Savage Rock Products - 6200 South 3100 East

1. The installations shall consist of only the following equipment:

   A. 2 Screen Deck Sets
   B. Jaw Crusher
   C. Cone Crusher
   D. Conveyors, Loaders, Haul Trucks, Generator, Compressor

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 300 tons/hr, Crusher Plant
   B. 1,000,000 tons/yr
   C. 16 hours/day
   D. 3,333 hours/yr of Crusher Operations

   Records/operations log shall be maintained to demonstrate compliance with the above limitations.

3. Water spays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

4. The moisture content of the construction aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 6.0% by weight an a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

5. Annual emissions for this source (the entire plant) are hereby established at 28.5 tons/yr for PM_{10}, 1.2 tons/yr for SO_2, 14.1 tons/yr for NO_x.

2.2.UU Staker Paving and Construction Company - North Beck Street

1. The installations shall consist of only the following equipment:

   A. Asphalt Plant, H & B Model 124" X 50' recycle plant and (2) associated Baghouses

   B. Primary Impact Crusher, horizontal shaft (9209), Hazemag, Model APSE-1313-QM, S/N - APS1313 302774, 1985

   C. Vibrating Scalping Grizzly, 5' X 16' (9311), Hewitt-Robins, Model VX14, S/N (NA), 1986

   D. Vibrating Feeder, 52" X 16' (9312), Hewitt-Robins, Model VL-9, S/N (NA), 1986

   E. Secondary Impact Crusher (9211), Black-Clawson, Model 60, S/N 60B4409 78, 1983

   F. Universal Jaw Crusher, S/N 546-PGR-3042

   G. Vibrating Screen Plant (9309), El Jay, Model 6' X 20', S/N 126743F0384, 1984

   H. Vibrating Screen Plant (9313), El Jay, Model 6' X 20', S/N (NA), 1986

   I. Vibrating Screen Plant (9304), Hewitt-Robins, Model 8' X 20', S/N E560 464501, 1980

   J. Aggregate Wash Plant (9315), Cedarapids, Model 5' X 16', S/N 516-232-B6-594, 1973

   (NA) means serial numbers not assigned as of this date, equipment not yet received.

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. The H & B Asphalt Plant

      1. PM_{10} virgin 6.71 lbs/hr .024 grains/dscf

      2. PM_{10} recycle 7.83 lbs/hr .028 grains/dscf

3.	SO_2	61.3 lbs/hr	210 ppmdv
4.	NO_x	25.2 lbs/hr	120 ppmdv

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

A. The H & B Asphalt Plant

	Method	Test Date
PM_{10}	201/201a	Test If Directed
SO_2	6	Test If Directed
NO_x	7	Test If Directed

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

A. For the Asphalt Plant:

1. 700 tons/hr
2. 700,000 tons/yr (including recycle mix)
3. 150,000 tons per year recycled asphalt pavement (RAP)
4. 2,500 hrs/yr

B. For the Aggregate Pit:

1. 750 tons/hr of crushing/screening production
2. 1,250,000 tons of mined material per year
3. 2,500 hrs/yr

The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

5. No more than 250,000 cubic yards per year of material shall be blasted for mining. There shall be no more than 30 blasts per year. The area to be blasted shall be soaked with water prior to blasting. Records of blasting which show the number of blasts and the volume of material blasted shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

6. For drilling of blasting holes, the contractor shall use a wet collar or dry collection equipment to reduce emissions.

7. For the asphalt plant the following operating parameters shall be maintained within the indicated ranges:

   A. Temperature of the gases exiting the baghouse shall be between 240°F and 400°F

   B. Asphalt mix temperature not to exceed 310°F

   They shall be monitored with equipment located such that an inspector can at any time safely read the output. The readings shall be accurate to within the following ranges:

   A. Plus or minus 10°F
   B. Plus or minus 10°F

   All instruments shall be calibrated against a primary standard at least once every 90 days. The primary standard shall be specified by the Executive Secretary.

8. A log of product temperature shall be taken at 15 minute intervals or more often, and a current year of data shall be available for evaluation by the Executive Secretary upon request.

9. The plant shall not operate with a stack exhaust flow rate in excess of 60,000 ACFM without prior approval from the Executive Secretary in accordance with Utah Air Conservation Regulation (UACR) 3.1.

10. The percent recycle asphalt processed in this plant shall not exceed the following:

    A. The percent by weight of recycled asphalt pavement (RAP) shall not exceed 60 - (6 X % moisture in RAP).

    B. Under no circumstances shall the percent by weight of recycle asphalt exceed 50%.

11. The sulfur content of any coal or any mixture of coals burned shall not exceed 0.60 percent by weight as determined by ASTM Method D-3177-75. The sulfur content shall be tested if directed by the Executive Secretary.

12. In addition to the requirements of this approval order, all provisions of 40 CFR 60, NSPS Subparts A and OOO apply to the following equipment:

    A. Primary Crusher #9209
    B. Vibrating Feeder #9312
    C. Screens #9309, #9311 and #9313

    All provisions of 40 CFR 60.90 (NSPS Subpart I) shall apply to the asphalt plant.

    The initial opacity observations shall consist of a minimum total time of three hours (30 six minute averages) for the above sources.

13. Water sprays, chemical dust suppression sprays, or enclosures shall be installed at the following points to control fugitive emissions:

    A. All crushers
    B. All screens
    C. All conveyor transfer points

    The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

14. Water shall be added to the mined material to be blasted and/or bulldozed such that before the material is moved, its moisture content, as determined by ASTM Method D-2216 on the -40 mesh portion of the sample, is greater than 4.0% by weight. This moisture content shall be maintained throughout subsequent crushing, screening and conveying circuits. The moisture content shall be tested once each day using the appropriate ASTM method. One sample shall be taken at each of the following locations:

    A. The pile located where the material that is pushed off the mine bench comes to rest.

    B. At each of the final product piles, samples shall be collected according to AASHTO Method T-27. Each sample shall be analyzed and recorded separately such that the moisture content at each point can be determined. Records of the moisture content shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. If opacity observations of the sources regulated by this moisture content condition indicate visible emissions in excess of 10% opacity, more moisture shall be added until 10% opacity can be achieved. An exceedance of 10% opacity shall not be considered a violation of an opacity standard, but failure to add additional moisture in that case shall be a violation of this condition.

15. All open areas shall be water sprayed and/or chemically treated to reduce fugitive dust, or controlled by some other means approved by the Executive Secretary. The disturbed area shall not exceed 70 acres without prior approval from the Executive Secretary.

16. Annual emissions for this source (the entire plant) are hereby established at 54.5 tons/yr for PM_{10}, 34.6 tons/yr for SO_2, 58.6 tons/yr for NO_x.

2.2.VV Staker Paving and Construction Company - 6820 West 7400 South

1. The installations shall consist of only the following equipment:

   A. Two Eljay 6' x 20" triple deck screen
   B. Two Eljay 54" Cone crushers
   C. One 775 Kw Genset
   D. Three 100' radial stackers
   E. One Eljay jaw crusher
   F. Two seven cubic yard front end loaders
   G. One D355 KOMATSU bulldozer

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:
   A. 500 tons/hr aggregate crushing and screening
   B. 250,000 tons/yr aggregate crushing and screening
   C. 12 hours/day
   D. 2160 hours/yr

   Records of consumption/production or throughput shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

3. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

4. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 7.5% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

5. Annual emissions for this source (the entire plant) are hereby established at 13.3 tons/yr for PM_{10}, 1.1 tons/yr for SO_2, 16.5 tons/yr for NO_x.

2.2.WW Staker Paving and Construction Company - 15290 South State Street

1. The installations shall consist of only the following equipment:
   A. Two Eljay 6′ x 20" triple deck screen
   B. Two Eljay 54" Cone crushers
   C. One 775 Kw Genset
   D. Three 100′ radial stackers
   E. One Eljay jaw crusher
   F. Two seven cubic yard front end loaders
   G. One bulldozer

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 500 tons/hr aggregate crushing and screening
   B. 250,000 tons/yr aggregate crushing and screening
   C. 12 hours/day
   D. 2160 hours/yr

   Records of consumption/production or throughput shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

3. Water spays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

4. The moisture content of the aggregate shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 8.8% by weight without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

5. Annual emissions for this source (the entire plant) are hereby established at 13.4 tons/yr for PM_{10}, 1.1 tons/yr for SO_2, 16.5 tons/yr for NO_x.

.2.XX Union Pacific Resources - Kennecott Minerals Corporation slag pit

Grit plant

1. The installations shall consist of only the following equipment located at the site:

   A. Mining operation with dozer & loader
   B. Loader at wash plant, & feed hopper
   C. Wash plant
   D. Scalping screen
   E. Dryer (gas fired)/baghouse dust control
   F. Bucket elevator, product screens, storage bins, and loadout conveyor with baghouse dust control
   G. Bag packing building with baghouse dust control
   H. Bulk loadout for rail/trucks with baghouse dust control
   I. 35 Ton Truck (part time)

2. The following production limits for the grit plant shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 40 tons/hr
   B. 51,000 tons/yr
   C. 16 hour/day
   D. 2080 hours/yr

   Grit production shall be determined by shipping records. The records shall be kept on a daily basis.

3. Reject fines from both the Grit Plant and the Ballast Plant shall either be covered with ballast material or be sprayed with an encrusting agent as dry conditions warrant or as determined necessary by the Executive Secretary to minimize fugitive dust.

4. The owner/operator shall use only Number 2 fuel oil or better as fuel or other fuel that can demonstrate sulfur content of less than 0.45% by weight. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of any fuel oil burned shall not exceed 0.45% by weight as determined by ASTM Method D-4294-89 or, as appropriate, the sulfur content of any fuel oil burned shall not exceed 0.25 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4294-89. The sulfur content shall be tested if directed by the Executive Secretary. Fuel consumption shall be determined by examination of vendor sales receipts which shall be maintained for two years.

These records shall be made available to the Executive Secretary upon request.

5. Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

A. Dryer baghouse stack

1.	PM_{10}	0.74 lbs/hr	0.016 grains/dscf

B. Process screens baghouse stack

1.	PM_{10}	0.61 lbs/hr	0.016 grains/dscf

C. Bulk loadout rail/truck baghouse stack

1.	PM_{10}	0.31 lbs/hr	0.016 grains/dscf

D. Grit bagging building baghouse stack

1.	PM_{10}	0.1 lbs/hr	0.016 grains/dscf

6. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

	Method	Test Date
A. Dryer stack		
PM_{10}	201/201a	Test if directed
B. Process screens stack		
PM_{10}	201/201a	Test if directed
C. Bulk loadout rail/truck stack		
PM_{10}	201/201a	Test if directed
D. Grit bagging building stack		
PM_{10}	201/201a	Test if directed

7. The baghouse flow rate shall be measured at the request of the Executive Secretary. The method shall be 40 CFR

60, Appendix A, Method 2.

8. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. The total acreage of the storage piles and plant yard shall not exceed 4 acres.

9. Water sprays or chemical dust suppression sprays shall be installed at the following points to control fugitive emissions:

   A. All unwashed material conveyor transfer points
   B. All rejected material conveyer transfer points

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

10. The owner/operator shall use only natural gas fuel in the dryer. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. Fuel consumption shall not exceed 18.6 MMcf/yr. Fuel consumption shall be determined by Mountain Fuel Supply billing.

Ballast Plant

11. The approved installations shall consist of only the following equipment located at the site:

   A. Mining operation with dozer
   B. Vibrating grizzly/scalper feeder system
   C. Underpile reclaim/vibrating feeder system
   D. Primary screen deck system/cone crusher
   E. Secondary screen deck systems
   F. field and reclaim conveyors
   G. Front-end loaders
   H. Two 35 Ton Trucks
   I. One Patrol
   J. Two Bobcat loaders

12. The following production limits for the Ballast Plant shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 600 tons/hr
   B. 1,248,000 tons/yr
   C. 16 hours/day Nov 1 to Feb 28
      24 hours/day all other times
   D. 2080 hours/yr

Ballast production shall be determined by shipping records. The records shall be kept on a daily basis.

13. Water sprays shall be installed at the following points to control fugitive emissions:

    A. Point #1 Vibrating feeder
    B. Point #6 Conveyor drop point from reclaim tunnel to plant feed conveyor
    C. Point #11 Conveyor Discharge from crusher
    D. Point #17 Transfer from field to stacking conveyors
       #23 rainbird type sprinklers at top of product radial stacker conveyers
    E. Any additional transfer point or screen as determined necessary by the Executive Secretary

    (These points are referenced to figure #2 of the notice of intent submitted April 30, 1986)

14. The owner operator shall established a written work practice to minimize stacker drop distance to five (5) feet or less except during stockpile building. A copy of the work practice shall be submitted to the Executive Secretary . A copy shall be available to the operator in a convenient location.

15. Annual emissions for this source (the entire plant) are hereby established at 28.1 tons/yr for PM_{10}, 1.50 tons/yr for SO_2, 15.30 tons/yr for NO_x.

2.YY The University of Utah - Salt Lake City: (Hot Water Plant)

1. The installations shall consist of only the following equipment:

   A. Boiler No. 1 (60 MMBTU/HR output)
   B. Boiler No. 2 (60 MMBTU/HR output)
   C. Boiler No. 3 (105 MMBTU/HR output)
   D. Boiler No. 4 (105 MMBTU/HR output)
   E. Boiler No. 5 (105 MMBTU/HR output)
   F. Coal and ash handling systems

2. Emission Limitations and Stack Testing:

   Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   For Coal Firing:

   A. For each boiler No. 1, and No. 2

1.	PM_{10}	23.8 lbs/hr	0.23 grains/dscf
2.	SO_2	71.3 lbs/hr	582 ppmdv
3.	NO_x	42.6 lbs/hr	485 ppmdv

   B. For each boiler No. 3, 4, and 5

1.	PM_{10}	41.6 lbs/hr	0.23 grains/dscf
2.	SO_2	125 lbs/hr	582 ppmdv
3.	NO_x	74.7 lbs/hr	485 ppmdv

   For Natural Gas Firing:

   A. For each boiler No. 1, and No. 2

1.	NO_x	12.2 lbs/hr	143 ppmdv

   B. For each boiler No. 3, 4, and 5

1.	NO_x	75.0 lbs/hr	560 ppmdv

   Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

A. Coal Firing: All (5) Boilers

	Method	Retest every
PM_{10}	201/201a	3 years
SO_2	6	Test If Directed
NO_x	7	3 years

B. Gas Firing: All (5) Boilers

	Method	Retest every
NO_x	7	3 years

3. Production Limitations:

The University of Utah shall fire natural gas in their hot water heating plant from November 1 to February 28 each season. The remainder of the year coal may be fired.

Coal consumption shall not exceed 18,730 tons per 12-month period, nor shall Natural Gas consumption exceed 490 million cubic feet per 12-month period without prior approval in accordance with Section 3.1, UACR. Compliance with these annual limitations shall be determined on a rolling monthly total. Based on the first day of each month a new 12-month total shall be calculated using the previous 12-months. Records of consumption shall be kept for all periods when the plant is in operation. Records of consumption shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. Fuel consumption shall be determined by examining sales receipts.

4. Fuel Requirements:

The sulfur content of any coal or any mixture of coals burned shall not exceed 0.60 percent by weight as determined by ASTM Method D-3177-75. In addition, the sulfur content (in weight percent) of each shipment of coal shall be recorded. This information shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. The sulfur content shall be tested if directed by the Executive Secretary.

5. Specific Requirements:

Henceforth, the practice of re-injecting flyash into the boilers for additional combustion shall be prohibited.

6. Annual emissions for this source (the entire plant) are hereby established at 74.3 tons/yr for PM_{10}, 219.3 tons/yr for SO_2, and 245.8 tons/yr for NO_x.

2.2.ZZ Utah Metal Works, Inc., - 805 Everett Ave. Salt Lake

1. The installations shall consist of only the following equipment:

   A. Wire Chopper and associated Baghouse and Cyclone
   B. Incinerator (for burning wire insulation)
   C. Aluminum Furnace

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Baghouse

PM_{10}	1.07 lbs/hr	.020 grains/dscf

   B. Incinerator

PM_{10}	3.02 lbs/hr	.080 grains/dscf

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

	Method	Retest every
A. Baghouse		
PM_{10}	201/201a	3 years
B. Incinerator		
PM_{10}	201/201a	3 years
C. Aluminum Furnace		
PM_{10}	201/201a	Test If Directed

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   For the Baghouse and Incinerator:

   A. 8 hours/day

B. 2,080 hours/yr

For the Aluminum Furnace:

A. 12 hours/day

B. 900 hours/yr

Records of production shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

5. The owner/operator shall use only natural gas or propane as fuel in the incinerator and in the furnace. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

6. The baghouse flow rate shall be measured at the request of the Executive Secretary. The method shall be 40 CFR 60, Appendix A, Method 2.

7. The particulate captured in the baghouse and cyclone shall be properly handled in order to prevent re-entrainment into the atmosphere.

8. Annual emissions for this source (the entire plant) are hereby established at 4.27 tons/yr for PM_{10}, 0.01 tons/yr for SO_2, 0.98 tons/yr for NO_x.

2.2.AAA Utah Power and Light - 40 N. 100 W.

1. The installations shall consist of only the following equipment:

   A. Two Boilers (30,000 lb steam per hour).

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Each of the two boilers:

NO_x	6.26 lbs/hr	143 ppmdv

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, and as directed by the Executive Secretary:

   A. Each of the two boilers:

	Method	Test Date
NO_x	7	Test If Directed

4. This source shall use natural gas as primary fuel in all fuel burning furnaces, ovens and boilers. Number 2 fuel oil or better shall be used only as a backup fuel to be used during natural gas curtailments and for maintenance firing. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UCAR. Fuel consumption shall be determined by gas meter readings and oil receiving and inventory records.

   The number 2 fuel oil may be used only during periods of natural gas curtailment, and for maintenance firings. Maintenance firings shall not exceed 1% of the annual plant BTU requirements. Records of fuel oil use shall be kept which shows the date the oil was fired, the duration in hours the oil was fired, the amount of fuel oil consumed and the reason for each firing.

5. Annual emissions for this source (the entire plant) are hereby established at 1.96 tons/yr for PM_{10}, 0.23 tons/yr for SO_2, 54.8 tons/yr for NO_x.

2.2.BBB Utah Power & Light - Gadsby

1. The approved installations shall consist of only the following equipment:

   A. Boiler No. 1 (726 MMBTU/HR)
   B. Boiler No. 2 (825 MMBTU/HR)
   C. Boiler No. 3 (1,155 MMBTU/HR)

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   For "Winter-time" operation, during the period from November 1st through February 28th.

   A. Boiler No. 1

NO_x	179 lbs/hr	336 ppmdv

   B. Boiler No. 2

NO_x	204 lbs/hr	336 ppmdv

   C. Boiler No. 3

NO_x	142 lbs/hr	168 ppmdv

   For "Summer-time" operation, during the period from March 1st through October 31st.

   A. Boiler No. 1

NO_x	255 lbs/hr	336 ppmdv

   B. Boiler No. 2

NO_x	290 lbs/hr	336 ppmdv

   C. Boiler No. 3

NO_x	203 lbs/hr	168 ppmdv

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, and as directed by the Executive Secretary:

   A. All Three Boilers, for each of two emission rates (winter and summer):

Method	Retest every
NO_x 7	2 yrs

The production rate during compliance testing for the summer-time emission limitations shall be performed at no less than 90% of the rated input heat capacity (653 MMBTU/HR for Boiler No. 1, 742 MMBTU/HR for Boiler No. 2, and 1,040 MMBTU/HR for Boiler No. 3). The production rate during compliance testing for the winter-time emission limitations shall be no less than 90% of the heat input rate correlating to the 70% capacity factor used to calculate the winter-time emission rates (460 MMBTU/HR for Boiler no. 1, 522 MMBTU/HR for Boiler No. 2, and 730 MMBTU/HR for Boiler No. 3).

4. The owner/operator shall use only natural gas as a primary fuel and number 2 fuel oil, or better, as back-up fuel in the boilers. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR. The sulfur content of any fuel oil burned shall not exceed 0.45 percent by weight as determined by ASTM Method D-4294-89. The sulfur content shall be tested if directed by the Executive Secretary. The number 2 fuel oil may be used only during periods of natural gas curtailment, and for maintenance firings. Maintenance firings shall not exceed 1 percent of the annual plant BTU requirement. In addition, maintenance firings shall be scheduled between April 1, and November 30 of any calendar year. Records of fuel oil use shall be kept which shows the date the oil was fired, the duration in hours the oil was fired, the amount of fuel oil consumed during each curtailment, and the reason for each firing. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UACR.

5. Annual emissions for this source (the entire plant) are hereby established at 61.3 tons/yr for PM_{10}, 67.7 tons/yr for SO_2, 2,983 tons/yr for NO_x. These amounts supersede those emissions that were credited to Utah Power and Light by Executive Secretary letter dated February 7, 1986. Also, these amounts are only in effect if the three boilers are capable of operating at the time the SIP is approved.

2.2.CCC Veterans Administration Medical Center

1. The installations shall consist of only the following equipment:

   A. Three Boilers (24.8 MMBTU/HR each)
   B. One Pathological Waste Incinerator

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. Any of the Three Boilers

NO_x	3.70 lbs/hr	143 ppmdv

   If more than one boiler is firing then the emission rate and concentration limitations shall be the sum of their individual limitations.

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

   A. Boilers

	Method	Test Date
NO_x	7	Test If Directed

4. This source shall use natural gas as primary fuel in all fuel burning furnaces, ovens and boilers. Number 2 fuel oil or better shall be used only as a backup fuel to be used during natural gas curtailments and for maintenance firing. If any other fuel is to be used, an approval order shall be required in accordance with Section 3.1, UCAR. Fuel consumption shall be determined by gas meter readings and oil receiving and inventory records.

   The number 2 fuel oil may be used only during periods of natural gas curtailment, and for maintenance firings. Maintenance firings shall not exceed 1% of the annual plant BTU requirements. Records of fuel oil use shall be kept which shows the date the oil was fired, the duration in hours the oil was fired, the amount of fuel oil consumed and the reason for each firing.

5. The quantity of fuel oil burned shall not exceed 50,000 gal/yr. Compliance with this annual limitation shall be determined on a rolling-monthly total. On the first day of each month a new 12-month total shall be calculated using the previous 12 months. Records of consumption shall be kept for all periods when the plant is in operation. Records of consumption shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. Fuel oil consumption shall be determined by evaluating sales receipts.

6. The following operating parameters shall apply to the pathological incinerator:

   A. The charge rate shall not exceed 250 lbs/hr

   B. The temperature in the secondary chamber shall be maintained at no less than 1,800°F and at no greater than 2,000°F

   Records of the quantities of refuse incinerated and the hours of operation shall be kept on a daily basis and shall be made available to the Executive Secretary upon request. They shall include a period of two years ending with the date of the request. Refuse destruction shall be determined by weighing the material before its disposal. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log. The temperature of the secondary chamber shall be monitored by equipment located such that an inspector can at any time safely read the output. The reading shall be accurate to within plus or minus 50°F. The instrument shall be calibrated against a primary standard at least once every 90 days. The primary standard shall be specified by the Executive Secretary.

7. Annual emissions for this source (the entire plant) are hereby established at 0.50 tons/yr for PM_{10}, 0.04 tons/yr for SO_2, 9.88 tons/yr for NO_x.

2.2.DDD Wolff Gravel Products, Inc - North Beck Street

1. The approved installations shall consist of only the following equipment:

A.	1 - D-155 bulldozer	S/N 16121
B.	1 - WA450 loader, 4.5 c.y.	S/N 10091
C.	1 - FR20 loader, 4.5 c. y.	S/N 80C145
D.	1 - Kolberg screen deck	S/N 1402 427 78 2
E.	1 - Feeder-dozer trap	S/N 1324 124 PDT 78
F.	1 - generator set, 50 KW	
G.	Associated conveyors	

2. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. 300 tons/hr
   B. 300,000 ton/yr
   C. 16 hours/day
   D. 4,000 hours/yr

   Aggregate production shall be determined by shipping records. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

3. The haul road length shall 0.3 miles without prior approval in accordance with Section 3.1, UACR. The speed of vehicles on the haul road shall not exceed 10 miles per hour without prior approval in accordance with Section 3.1, UACR.

4. All open areas shall be water sprayed and/or chemically treated to reduce fugitive dust, or controlled by some other means approved by the Executive Secretary. Control is required at all times (i.e. 24 hrs/day) including weekends and holidays until such time as the pit has been reclaimed and the top soil has been replaced. The disturbed area shall not exceed 28.8 acres without prior approval from the Executive Secretary.

5. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. There shall be only 8 storage piles, and the total acreage of the storage piles shall not exceed 2.5 acres.

6. Water sprays or chemical dust suppression sprays shall be installed at the following points to control

fugitive emissions:

A. All screens
B. All conveyor transfer points

The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitation.

7. The moisture content of the road base shall be maintained at a value of no less than 4.0% by weight. The silt content of the product shall not exceed 6% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

8. The water holding tank and spray system shall be installed and operated to the extent that sufficient moisture is added to the mined material prior to mining that the opacities designated in paragraph 4 shall not be exceeded.

9. Annual emissions for this source (the entire plant) are hereby established at 3.30 tons/yr for PM_{10}, 0.30 tons/yr for SO_2, 3.40 tons/yr for NO_x.

`.2.EEE W.W. & W.B. Gardner Construction Company - Beck Street

1. The installations shall consist of only the following equipment plus any equipment not capable of producing air contaminants:

   A. At the Victory Road Aggregate Pit

      Cedar Rapids 2236 Jaw Crusher

      Eljay 54" Cone Crusher

      Barmac Impact Crusher

      (2) Cedar Rapids 5' X 16' Triple Deck Screens

      (all) Associated Conveyors

      (1) Generator Set

      (1) Bulldozer

      (1) Front End Loader

   B. At the Asphalt Plant

      Cedar Rapids model 88-28 Drum Mix Asphalt Plant

      Baghouse

      (1) Front End Loader

2. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

   A. The Cedar Rapids Asphalt Plant

1.	PM_{10}	6.10 lbs/hr	0.024 grains/dscf
2.	SO_2	12.0 lbs/hr	40.7 ppmdv
3.	NO_x	9.90 lbs/hr	46.6 ppmdv

3. Stack testing to show compliance with the above emission limitations shall be performed for the following emission points and air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see paragraph 2.1.A. for more details), and as directed by the Executive Secretary:

A. The Cedar Rapids Asphalt Plant

		Method	Test Date
1.	PM_{10}	201/201a	Test If Directed
2.	SO_2	6	Test If Directed
3.	NO_x	7	Test If Directed

4. The following production limits shall not be exceeded without prior approval in accordance with Section 3.1, UACR:

   A. For the Asphalt Plant:

      1. 275 tons/hr
      2. 250,000 tons/yr
      3. 2,500 hrs/yr

   B. For the Aggregate Pit:

      1. 300 tons/hr of crushing/screening production
      2. 300,000 tons of mined material per year
      3. 2,500 hrs/yr

   Asphalt, concrete and pit production shall be determined through the use of weigh scales and recording of the weights. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining an operations log.

5. For the asphalt plant the following operating parameters shall be maintained within the indicated ranges:

   A. Temperature of the gasses exiting the baghouse not to exceed 300°F
   B. Asphalt mix temperature not to exceed 310°F
   C. Asphalt oil temperature not to exceed 330°F

   They shall be monitored with equipment located such that an inspector can at any time safely read the output. The readings shall be accurate to within the following ranges:

   A. Plus or minus 10°F
   B. Plus or minus 10°F
   C. Plus or minus 10°F

   All instruments shall be calibrated against a primary standard at least once every 90 days. The primary standard shall be specified by the Executive Secretary.

6. The air to cloth ratio of the baghouse shall not exceed

5.5:1 when operating the plant. At least three baghouse modules shall be used when operating with a stack exhaust gas flow rate of up to 45,000 ACFM. Four modules shall be used when operating at stack exhaust gas flow rates between 45,000 AND 60,000 ACFM. The plant shall not
operate with a stack exhaust flow rate in excess of 60,000 ACFM without prior approval from the Executive Secretary in accordance with Utah Air Conservation Regulation (UACR) 3.1.

7. The sulfur content of any coal or any mixture of coals to be burned shall not exceed 0.60 percent by weight as determined by ASTM Method D-3177-75. The sulfur content shall be tested if directed by the Executive Secretary.

8. This plant is approved for asphalt production using 100% virgin materials only. The use of this plant to produce recycle asphalt products shall require approval of the Executive Secretary in accordance with Section 3.1, Utah Air Conservation Regulations (UACR).

9. Water sprays, chemical dust suppression sprays, or enclosures shall be installed at the following points to control fugitive emissions:

   A. All crushers
   B. All screens
   C. All conveyor transfer points

   The sprays shall operate to the extent necessary to keep the equipment operation within the opacity limitations established.

10. Water shall be added to the mined material (to be bulldozed) such that before the material is moved, its moisture content, as determined by ASTM Method D-2216 on the -40 mesh portion of the sample, is greater than 4.0% by weight. This moisture content shall be maintained throughout subsequent crushing, screening and conveying circuits. The silt content of the product shall not exceed 15% by weight on a daily average without prior approval in accordance with Section 3.1, UACR. The moisture and silt content shall be tested if directed by the Executive Secretary using the appropriate ASTM method.

11. All open areas shall be water sprayed and/or chemically treated to reduce fugitive dust, or controlled by some other means approved by the Executive Secretary. Fugitive dust shall be limited to the opacity

limitation. The disturbed area shall not exceed 35 acres without prior approval from the Executive Secretary.

12. The storage piles shall be watered to minimize generation of fugitive dusts as dry conditions warrant or as determined necessary by the Executive Secretary. The total acreage of the storage piles shall not exceed one acre.

13. Annual emissions for this source (the entire plant) are hereby established at 24.1 tons/yr for PM_{10}, 6.19 tons/yr for SO_2, 13.0 tons/yr for NO_x.

UTAH STATE IMPLEMENTATION PLAN
SECTION IX PART B
CONTROL MEASURES FOR AREA AND POINT SOURCES
SULFUR DIOXIDE

SECTION IX.B.1 HISTORY OF NONATTAINMENT AREAS DESIGNATION AND SIP SUBMITTALS

In the Federal Register of September 11, 1978, there were three areas in Utah that were designated as nonattainment for sulfur dioxide (SO_2). These three areas include:

1. Salt Lake County
2. Tooele County
3. Cedar City

The designation of Cedar City as a nonattainment area for SO_2, made by the State, was based on ambient air quality data collected at the State's monitoring station on the campus of Southern Utah State College (now Southern Utah State University).

The designation of Salt Lake and Tooele Counties was made by the U.S Environmental Protection Agency (EPA), based on data collected at the State's ambient air monitoring stations in Magna and Tooele. The old reverberatory furnace system at the Kennecott Copper Corporation's Utah Smelter was still in operation at that time. On March 13, 1981, EPA revised the nonattainment designation for Tooele County to exclude all areas except those above 5600 feet. The main concern of the SIP for Salt Lake and Tooele Counties as proposed by the State and EPA's proposed approval was control of emissions from Kennecott.

On August 16, 1981 the State submitted a State Implementation Plan (SIP) for the control of SO_2 in Salt Lake County, Tooele County, and Cedar City to the EPA. The primary control measure in the SIP for Salt Lake and Tooele Counties was the construction of a new smelter at Kennecott Copper Corporation to replace the old reverberatory furnace system. The only control measure in the SIP for Cedar City was enforcement of the existing limitation for sulfur content in fuel oil used at Southern Utah State College. In December of 1983, Cedar City was redesignated an attainment area for SO_2.

On March 23, 1984, in 49 FR 10946-10950, EPA proposed approval of this implementation plan for control of SO_2 from the Kennecott smelter contingent upon submittal of an approvable good engineering practice stack height demonstration. Prior to final approval, EPA requested that the State make several additional commitments as a part of the SIP.

In February 1982, EPA promulgated "stack height" regulations (47 FR 5864). In October 1983, portions of those regulations were overturned by the U.S. Court of Appeals for the D.C. circuit. The outcome of this decision affected the Utah SIP because the modeling to demonstrate attainment with the National Ambient Air Quality Standards (NAAQS) for SO_2 considered emissions from Kennecott Copper Corporation's tall stack. If it was determined that the stack height did not meet "good engineering practices", the results of the model might be affected. In order to resolve this issue, the Utah Air Conservation Committee (now the Air Quality Board) committed to the following:

1. When EPA promulgated new regulations applicable to stack heights as mandated by the courts, the Committee would require Kennecott to prepare a demonstration of the adequacy of the smelter main stack to assure attainment of ambient standards when stack height was taken into account. Upon approval by the Committee of the required demonstration, the Committee would then submit the demonstration to EPA.

2. If the demonstration required by the Committee showed that attainment could not be achieved based on any new stack height requirements promulgated by EPA as a result of the court decision, the Committee was to revise the SIP consistent with the new height requirements.

In 1986, after questions concerning the stack height regulations were resolved, the State submitted Section 17 (since renumbered to Section 16) of the Utah Implementation Plan, Demonstration of GEP Stack Height, to EPA. This SIP demonstrated that the height of the Kennecott tall stack met the criteria for "good engineering practices." EPA was required to approve or disapprove this SIP within one year of submittal, and to also issue final approval or disapproval of the SO_2 SIP, based on the stack height determination for Kennecott's tall stack.

On November 15, 1990, Congress amended the Clean Air Act. Section 107(d)(1)(C)(i) of the Amended Act states that any area designated as non-attainment on November 15, 1990 is automatically redesignated as non-attainment. Because the SO_2 SIP had not yet been approved, Salt Lake and Tooele Counties were automatically redesignated as non-attainment areas, even though no violations of the standard had been recorded since 1980. Section 191(b) of the amended Act requires any state with a non-attainment area lacking a fully-approved implementation plan for SO_2 as of November 15, 1990 to start over again, and resubmit a new SIP by May 15, 1992. Because of the amendments to the Clean Air Act, the State was required to resubmit both the GEP Stack Height SIP, and the SO_2 SIP to the EPA.

On December 18, 1991, the State submitted a new GEP Stack Height SIP to the EPA. Once again, this SIP demonstrated that the height of Kennecott Copper Corporation's tall stack met "good engineering practices." Based on this demonstration, the modeling performed in 1981 SIP to demonstrate attainment of the NAAQS standard for SO_2 in Salt Lake and Tooele Counties is still a valid demonstration.

IX.B.2 SULFUR DIOXIDE CONCENTRATIONS

Sulfur dioxide concentrations have been measured at two stations in the Salt Lake County nonattainment area, at one station in the Tooele County nonattainment area, and at three stations in the Cedar City nonattainment area. A summary of the data for Salt Lake City and Cedar City are shown in Figure IX.B.1.

Sulfur Dioxide (ppm)

Sulfur Dioxide (ppm)

	Salt Lake 2nd High 24-Hr Avg.	Salt Lake # Greater than NAAQS	Magna 2nd High 24-Hr Avg.	Magna # Greater than NAAQS	Cedar City 2nd High 24-Hr Avg.	Cedar City # Greater than NAAQS
1977					.02	0
1978					.04	0
1979	.05	0	.15	49	.04	0
1980	.11	0	.17	35	.02	0
1981				0		
1982	.04	0	.09	0		
1983	.03	0	.06	0		
1984	.08	0	.07	0		
1985	.07	0	.08	0		
1986	.09	0	.00	0		
1987	.02	0	.01	0		
1988	.04	0	.07	0		
1989	.07	0	.07	0		
1990	.03	0	.07	0		

	Salt Lake 2nd High 3-Hr Avg.	Salt Lake # Greater than NAAQS	Magna 2nd High 3-Hr Avg.	Magna #Greater than NAAQS
1982	.10	0	.22	0
1983	.08	0	.22	0
1984	.11	0	.17	0
1985	.12	0	.14	0
1986	.13	0	.02	0
1987	.05	0	.20	0
1988	.08	0	.19	0
1989	.13	0	.16	0
1990	.07	0	.15	0

NAAQS Primary = 0.03 ppm, annual arithmetic mean
0.14 ppm, 24-hour average concentration
Secondary = 0.5 ppm, 3-hour average concentration

Note: 24-hour and 3-hour NAAQS may be exceeded once each year

FIGURE IX.B.1

IX.B.3 CONTROL STRATEGIES

IX.B.3.a. Cedar City.

The State operated an ambient monitoring station which measured concentrations of SO_2, and particulates in Cedar City, Utah from April 1975 to 1980.

Violations of the primary and secondary Ambient Air Quality Standards for SO_2 were observed in 1975 and only the Primary NAAQS was violated in 1976 and 1977. The 1977 maximum 24-hour average concentration was 0.21 ppm and the second high 24-hour running average was 0.18 ppm. A review of the emission inventory indicated that there are no major sources of SO_2 in Cedar City.

An investigation was conducted to determine the source of SO_2 which resulted in violations of the NAAQS. The State's monitoring station was located on the campus of the College of Southern Utah (now Southern Utah State University) and was southwest of and near the college heating plant which is fired with fuel oil. A review of the monitoring data showed that violations of the NAAQS occurred during the winter season when easterly winds were observed. Two special-purpose monitoring units were installed upwind from the original monitoring site to determine how widespread the high concentrations might be and to help pin-point the source. Although SO_2 was detected by the new units, the concentrations were well below the NAAQS. The data collected at the two stations are shown in Figure IX.B.2. As a result, efforts to locate the source were directed to the vicinity of the original monitoring unit.

It was believed that the station had been fumigated by the plume from the college heating plant. A sample of the fuel oil used in the plant was analyzed; the sulfur content (8.1% by weight) was substantially higher than that allowed by the Utah Air Conservation Rules (1.5% by weight).

The college was informed of the violation of the sulfur content of fuels requirement. They immediately acquired a supply of fuel oil which met the requirements. That change is the control strategy and resulted in attainment of the NAAQS for SO_2 in Cedar City. The original monitoring station was left in operation until 1978 to determine the attainment status. One of the special-purpose monitoring stations was also left in operation until 1980.

Maintenance of the NAAQS for SO_2 in Cedar City will be achieved through enforcement of the sulfur content of fuels regulations. (See R307-203-1).

IX.B.3.b. Salt Lake and Tooele Counties.

A careful review of the emissions inventory and diffusion modeling which was coordinated by the State indicated that the emissions from one point source, Kennecott Copper Corporation, resulted in violations of the NAAQS for SO_2 which were observed in both counties.

Ambient measurements taken by the Department of Health in Salt Lake County indicated that the NAAQS were violated only at the site in Magna, Utah. Based on this information, the Magna monitoring site was used as the control point for development of the control plan. No violations of the NAAQS have been observed at any of the monitoring stations since 1980.

To attain and maintain the ambient air quality standards in Salt Lake and Tooele Counties, it was and continues to be necessary to control SO_2 emissions from the Kennecott operation. In 1981, the Utah Air Conservation Rules were revised to include emission limitations and control requirements for the following Kennecott operations:

1. Smelter Main Stack
2. Fugitive Emissions
3. Power Plant
4. Molybdenite Heat Treaters
5. Refinery

As part of the approval process for the 1981 submittal by the State, the EPA performed a modeling analysis. Figure IX.B.3 shows the distribution and expected concentrations of SO_2 as determined by diffusion modeling, using the CDMQC model. The highest predicted concentration of SO_2 was at Lake Point, which is on the property of Kennecott Copper Corporation. Figure IX.B.4 shows the location of Lake Point as well as the 5600-foot level contour of the Oquirrh Mountains and the Kennecott Utah Copper property boundary. In 1979, Kennecott established a monitor at Lake Point to measure SO_2 concentrations.

On August 15, 1991 the State promulgated a State Implementation Plan for the control of PM_{10} in Salt Lake County. Because SO_2 is a precursor of PM_{10}, the SIP relied heavily on reductions of SO_2 emissions to control PM_{10} in the Salt Lake/Davis County nonattainment areas. As part of the PM_{10} SIP, Kennecott Copper Corporation agreed to install double-contact acid plant technology as well as other control measures that would result in SO_2 emission reductions from the facility. As required to protect the 3-hour NAAQS for SO_2, a 3-hour emission limit has been included in Section IX, Part H, Emissions Limits. The discussion in IX.B.3.c below details the development of that limit.

By comparing the ratio of Kennecott Copper Corporation's 1981 SO_2 emissions limitations and the 1991 PM_{10} SIP emissions limitations, and using the modeling/monitoring ratio established in the 1981 SO_2 SIP, the State is able to demonstrate that the SO_2 NAAQS will not be exceeded in Salt Lake County or Tooele County as detailed in IX.B.3.d below.

IX.B.3.c. Development of the 3-hour Tall Stack Emission Limit.

One of the principle requirements of the 1992 SO_2 SIP revision is the establishment of a 3-hr emission limit for the tall stack at the Kennecott smelter. This limit will reflect the new levels of control agreed upon as part of the PM_{10} SIP which resulted in new emission limits for both 24-hour and annual averaging periods. This new level of control will be achievable through the application of available double contact acid plant technology.

The total emissions from the tall stack are composed of two distinct sources: 1) fugitive smelter emissions captured by the secondary ducting, and 2) tail-gas emissions from the acid plant(s).

Kennecott Utah Copper (KUC), in a meeting held January 10, 1992, proposed to the State a 3-hour emission limit of 6,900 lbs/hr. This limit contains a 4,500 lb/hr contribution from the ducted fugitive emissions, which is the same estimated contribution used to establish the 24-hr limit of 5,700 lbs/hr which was used in developing the PM_{10} SIP. This is based on an assumption that fluctuations in these fugitive emissions should be negligible when comparing a 3-hr period with a 24-hr period. The remainder of the 6,900 lb/hr limit would then be 2,400 lbs/hr from the acid plant(s). The contribution from the acid plant(s) would correlate to a tailgas SO_2 concentration of 1,300 ppm. In a subsequent letter, dated 1/14/92, KUC presented its' rationale for the selection of this tailgas concentration. That letter is contained in the technical support document, and is summarized below.

KUC has based their proposal of 1,300 ppm on certain sections of an EPA document titled 'Review of New Source Performance Standards for Primary Copper Smelters' (1984). They begin with Table I-2 (from appendix I of that document, and herein referred to as Fig. IX.B.5) which summarizes SO_2 concentration data collected (in 1973) every 15 minutes from the tailgas of a double contact acid plant at the ASARCO copper smelter in El Paso, Texas. The table compares the probability of exceeding various concentration levels (from 150 to 750 ppm) with the effect of different averaging times used to calculate the measured concentration (from 15 minutes to 10 hrs). As the averaging time increases, and as the reference concentration level increases, the probability of exceeding that reference level decreases significantly. For a 3-hour averaging period, the probability of exceeding a tailgas concentration of 750 ppm is reported by the study as 0.5%.

From that point, KUC looked at the highest concentration reported for the representative averaging period (also reported in Table I-2), which for the 3-hour period was 1,238 ppm, and averaged the two. This procedure yielded a value of: (750 ppm + 1,238 ppm)/2 = 994 ppm.

The next step was to account for the effects of normal catalyst deterioration with a "safety" factor of 30%. Thus: 994 ppm X 1.3 = 1,292 ppm, and this number was finally rounded up to the 1,300 ppm which KUC proposed.

During the review of the KUC proposal, the State determined the origin of the 30% deterioration level. Table G-3 of the same EPA document summarizes tailgas SO_2 concentrations from a different study - one which compared the tailgas concentration of Kennecott's No.6 acid plant with the tailgas concentration of their No.7 acid plant. The data for this study was collected over a three day period in 1972, and during that time the average concentration of the No.7 plant exceeded that of the No.6 plant by roughly 30%. This difference in performance was attributed entirely to the deterioration of the catalyst in the No.7 plant, even though the two plants are of different age, design and manufacture. Both plants, however, routinely clean their catalysts over a 12-month cycle, and while the No.7 plant was in its twelfth and final month, the No.6 plant was in only the second month of its cycle. The assumption was that because catalyst deterioration (primarily a function of pressure drop across the catalyst bed) should occur exponentially, and should become a factor only during the latter stages of the cleaning cycle, this was the only difference in the performance of the two acid plants. Thus, said the KUC study, it would be reasonable to apply a 30% deterioration factor when establishing a regulatory emission factor for a new double contact sulfuric acid plant.

There is no question as to whether or not the catalyst in an acid plant will deteriorate and thereby diminish the performance of the plant. Therefore, it is the responsibility of the State to verify that a proposed 30% is a reasonable performance reduction estimate. When the ASARCO study was further analyzed, it was pointed out that the data collection took place during what was considered to be the second and third quarters of the plant's 24-month cleaning cycle. Thus, making the same "exponential" assumption, there would have been little if any adverse effect due to catalyst deterioration for that double contact acid plant. Recognizing that such effects should be accounted for when establishing an emission limit, the study team posed the question of how much deterioration could reasonably be expected, and their "discussions with the designers of the ASARCO acid plant indicated that up to a 10% increase in emissions was expected before renewal of the catalyst."

Furthermore, in an effort to apply the results of their findings to other acid plants, the study team made the following statement in their conclusion: "To account for situations of increased emissions due to higher inlet (SO_2) concentrations of up to 9%, the results of Table I-2 require prorating upward a maximum of 200 ppm".

Therefore, based on the above analysis, it was the decision of the State to adopt the conclusions of the ASARCO study for the purposes of establishing a 3-hour emission limit for the tailgas SO_2 concentration of KUC's new acid plant. As a result of this position, the State: 1) accepted KUC's starting point of 750 ppm as corresponding to a 99.5% confidence level (even though Table I-2 showed the same degree of certainty associated with 700 ppm); 2) added 200 ppm to that figure to account for possible differences in or fluctuations of the inlet SO_2 concentration; and 3) allowed a 10% margin of "safety" to account for the effects of catalyst deterioration, thereby arriving at a 3-hour SO_2 limit as follows:

(750 ppm + 200 ppm) X 1.1 = 1,045 ppm

which would correlate to a lb/hr figure as:

1,045 ppm X (2,400 lbs/hr / 1,300 ppm) = 1,929 lbs/hr

which could be rounded to 1,950 lbs/hr, and, added to the 4,500 lbs/hr contribution from the ducted fugitive emissions, to arrive at a 3-hour average emission limit of 6,450 lbs/hr.

IX.B.3.d. Analysis of Control Strategy.

The SO_2 emission limits as required for the control of PM_{10} and SO_2 for the annual, 24- and 3-hour averages for the main smelter stack are, therefore, respectively, 3,240, 5,700 and 6,450 lb/hr. The annual and 24-hour limits represented RACT for the development of the PM_{10} SIP. The 3-hour limit represents the amount of control sufficient for the attainment of the 3-hour SO_2 standard in the nonattainment area. Low level emissions (low stack and fugitive emissions) are not considered in evaluating the impacts on the elevated terrain (i.e., Lake Point) for three reasons: 1) The exact quantities of fugitive emissions are unknown; 2) Low level emissions have not caused any violations at low level monitors since 1980, and their impacts on the high level terrain would appear even lower or probably insignificant; and 3) Ignoring low level emissions and attributing impacts solely to the main stack will be more conservative for the control of main stack emissions.

(1) Evaluation of 24-hour Impacts on Lake Point Using Previous Modeling Results

EPA previously used the Valley model to estimate impacts at different distances and elevations. The model evaluated annual impacts using an annual emission rate of 2,293 g/sec or 18,200 lb/hr. The model then converted the annual impacts to 24-hour averages. The modeling results are contained in the technical support document.

Both Lake Point and a site [designated as "Point A"] which is the point closest to the main stack on elevated terrain outside Kennecott property, are about 4.5 km distance from the main stack, and are shown on a map contained in the technical support document. The previous EPA modeling results did not include impacts at 4.5 km distance. Use of a linear interpolation gives a 24-hour impact of 570 :g/m^3 at Lake Point.

Using the new annual emission rate of 3,240 lb/hr, the 24-hour impact is then estimated as

(3,240 lb/hr)x(570 ug/m3)/(18,200 lb/hr) = 102 ug/m3 = 0.039 ppm.

To be more conservative in estimating the 24-hour impact, the new 24-hour emission rate of 5,700 lb/hr is used as an annual emission rate. The 24-hour impact is evaluated as

(5,700 lb/hr)x(570 ug/m3)/(18,200 lb/hr) = 179 ug/m3 = 0.068 ppm,

which is lower than the 24-hour standard of 0.14 ppm.

To be even more conservative in estimating the 24-hour impact, the new 3-hour emission rate of 6,450 lb/hr is used as an annual emission rate. The 24-hour impact is then evaluated as

(6,450 lb/hr)x(570 ug/m3)/(18,200 lb/hr) = 202 ug/m3 = 0.076 ppm,

which is still lower than the 24-hour standard of 0.14 ppm.

(2) Evaluation of 24-hour Impacts on Lake Point Using Previous Monitoring Data

Another method to estimate the impact of the main stack emissions using the new emission limits is to use previous monitoring data at Lake Point and stack emission rates. The monitoring and emission data for the worst case episode of 0.33 ppm of 24-hour average on 11/30/79 is contained in the technical support document.

The 24-hour average emission rate at the hour of the maximum running 24-hour average concentration of 0.33 ppm was 38,228 lb/hr. Because the plume from the stack took an unknown time to reach Lake Point, the maximum concentration observed at the monitor was caused by emissions prior to the hour when the measurements were taken. Since the emission data showed that the emission rates prior to the highest concentrations were higher than 38,228 lb/hr, using an emission rate of 38,228 lb/hr results in a more conservative approach. The 24-hour impact of the new 24-hour emission rate is estimated as

(5,700 lb/hr)x(0.33 ppm)/(38,228 lb/hr) = 0.049 ppm,

which is also lower than the 24-hour standard.

(3) Evaluation of 3-hour Impacts on Lake Point

The monitoring data at Lake Point and emission data can be utilized to evaluate the 3-hour impact from the new emission rates. From the monitoring data for running half-hour contained in the Technical Support Document, the maximum 3-hour average concentration during the episode period on 11/30/79 was conservatively estimated as 1.0 ppm.

The exact 3-hour average emission rate causing the 1.0 ppm impact is unknown. Since the emission data in the technical support document indicates that the emission rate of 24-hour average was lower than that of the 3-hour average, using the 24-hour emission rate of 38,228 lb/hr as the 3-hour emission rate will give more conservative results. The 3-hour impact from the new 3-hour emission rate is evaluated as

(6,450 lb/hr)x(1.0 ppm)/(38,228 lb/hr) = 0.17 ppm,

which is also below the 3-hour standard.

(4) Summary

The estimate results for maximum impacts from the new stack emissions on Lake Point are summarized in Table IX.B.1.

Estimated impacts on Lake Point

Average	Emission rate (lb/hr)	NAAQS (pm)	Impact (ppm)	Evaluation method
24-hr	5,700	0.14	0.068 0.049	modeling monitoring
3-hr	6,450	0.5	0.27 0.17	modeling monitoring

IX.B.3.e. Protection of the 3-hour SO_2 Standard.

The EPA has required the State to ensure that the 3-hour SO_2 NAAQS will be protected, as well as the 24-hour and annual NAAQS.

The emission limitation for the tall stack at Kennecott Copper Corporation was established using a 3-hour average and a multi-point formula in the 1981 SO_2 SIP. The 1991 PM_{10} SIP revised this limitation to establish a 24-hour standard for SO_2 emissions and eliminated the multi-point limitations allowed in the 1981 SIP. The EPA accepted the new SO_2 limitation as a control strategy for the PM_{10} SIP, but required the State to develop a 3-hour emission limit for the tall stack as part of the new SO_2 SIP. Section IX, Part H, Emission Limits, has been revised to include a 3-hour emission limitation for the smelter tall stack as detailed in IX.B.3.d above.

The EPA also required the State to revise the sulfur content of fuels requirement in it's regulations. The existing rules specified a limit for the sulfur content of fuels, but did not specify an averaging time or specific ASTM methods. R307-203-1 has been revised to include a 24-hour averaging period for the sulfur content of coal, fuel oil, and fuel mixtures, and to specify the ASTM methods to be used to demonstrate compliance with the limitations and reporting requirements. It is the state's position that, because there is no high-sulfur natural gas in Utah, there is no need for a rule which specifies testing methods for determining sulfur content of natural gas or fuel mixtures containing natural gas.

Subsection R307-1-4.6 was revised to include a 3-hour averaging time for Sulfur Burning Production Sulfuric Acid Plants.

IX.B.4 EMISSION LIMITATIONS.

See Section IX, Part H of the Utah Implementation Plan for the new emissions limitations for Kennecott Copper Corporation.

See R307-203-1 for limitations on the sulfur content of fuels.

IX.B.5 ADEQUACY DEMONSTRATION.

Monitoring performed in Cedar City, Magna, and Salt Lake City has shown no violations of the NAAQS for SO_2 from 1981 to 1992. The control measures proposed in this SIP have already been shown through actual measurements over the recent past 10-year period to be adequate to maintain the standards.

	Sulfur Dioxide (ppm)			
	Annual Mean	**2nd High 24-Hr. Avg.**	**#Greater Than Nat'l Primary 24-Hr.**	**#Greater Than Nat'l Secondary 3-Hr.**
Cedar City (1st East)				
1977	.009	.02	0	0
1978	.00*	.04	0	0
1979	.00*	.04	0	0
1980	.00*	.02	0	0
Cedar City (High School)				
1977	.005	.01	0	0

NAAQS - Primary - 0.03 ppm annual arithmetic mean, 0.14 ppm 24 hour average concentration; Secondary - 0.5 ppm 3 hour average concentration

NOTE: 24-Hr. and 3-Hr. NAAQS may be exceeded once each year.

* Annual mean is less than .005 ppm SO_2

Figure IX.B.2

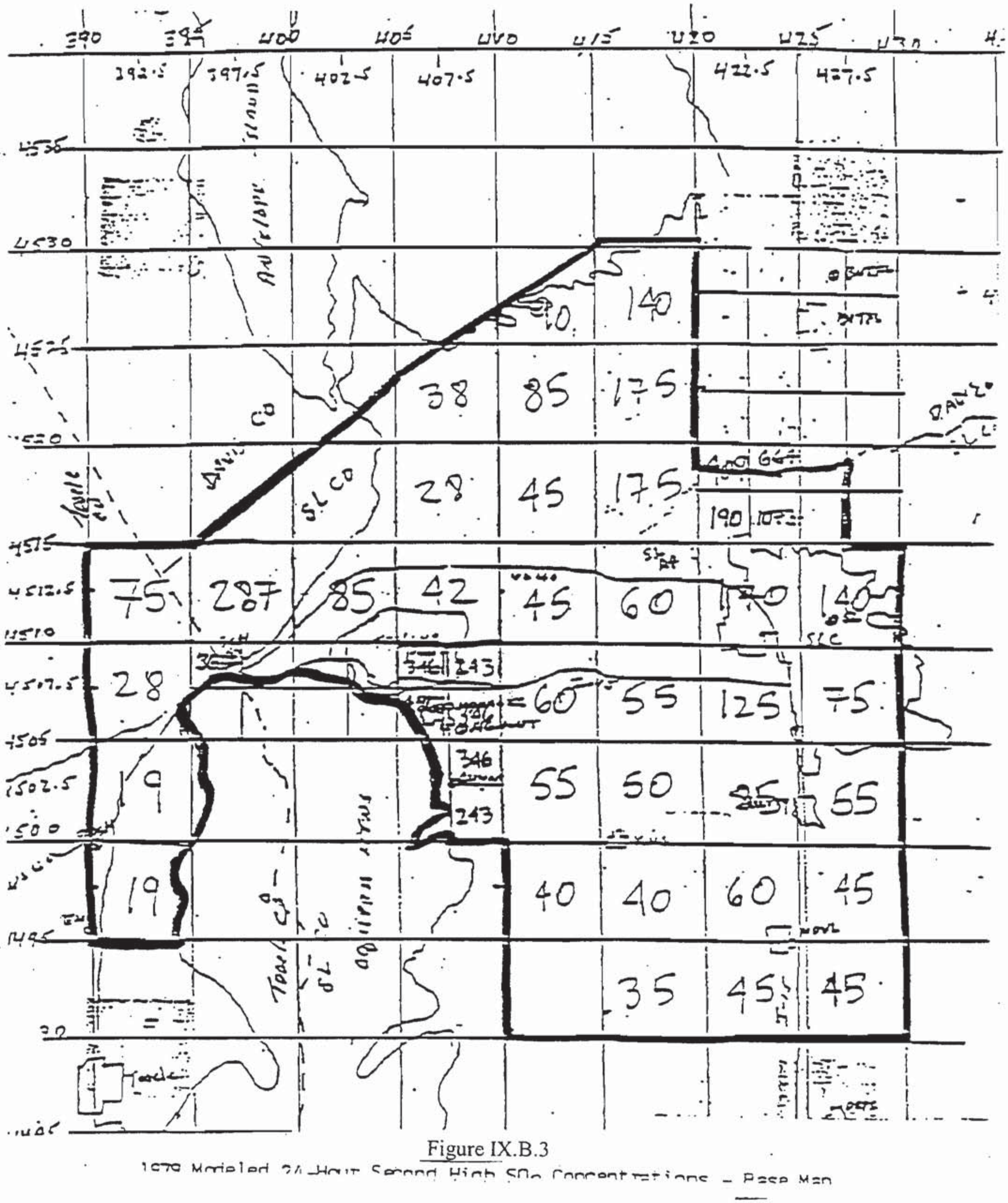


Figure IX.B.3

1979 Modeled 24-Hour Second High SO_2 Concentrations – Base Map

Attachment :

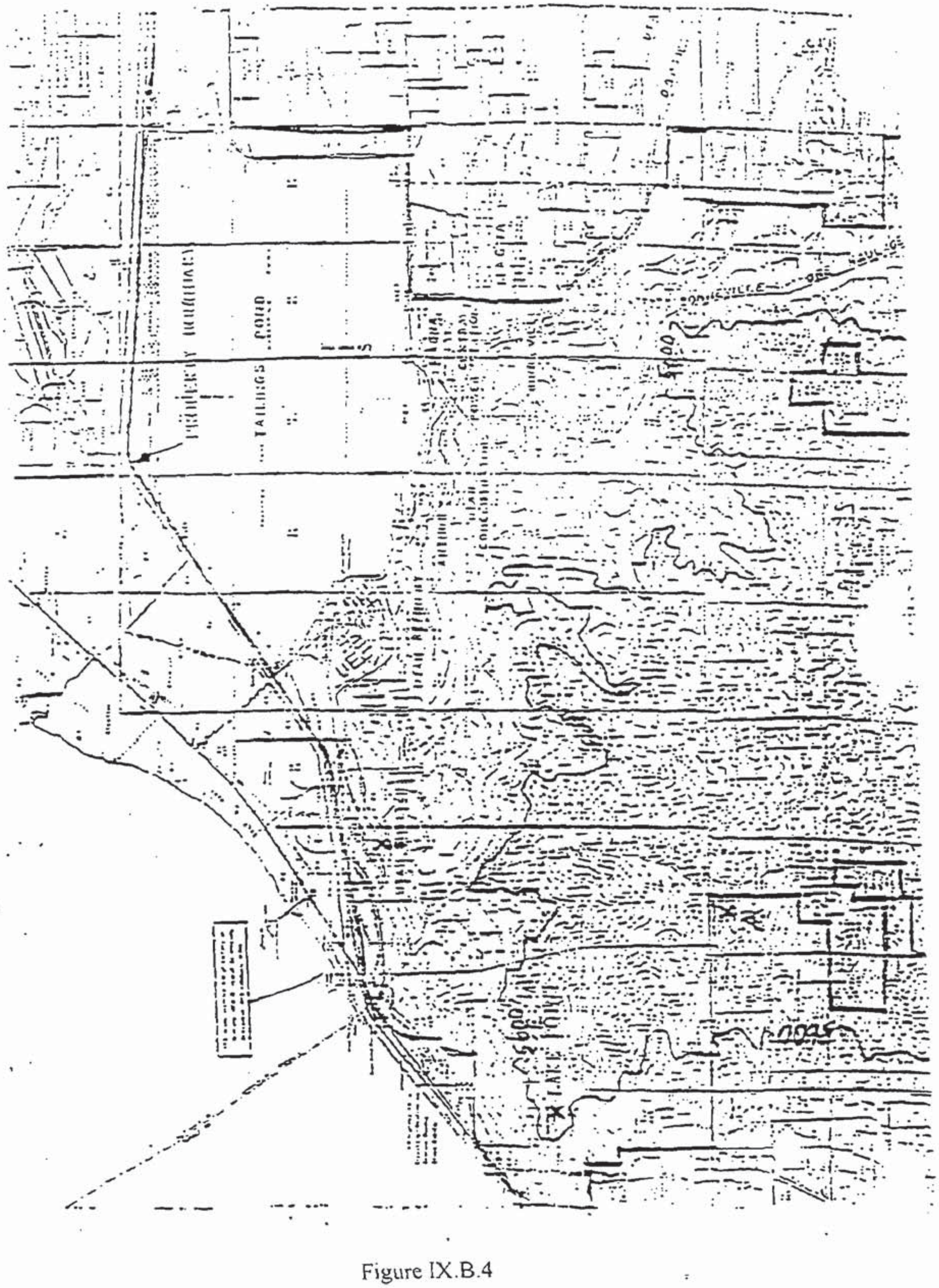


Figure IX.B.4

The Effect of Reference Concentration Level and Averaging Time on the Percentage of Excursions

Averaging Time	Number of Readings	150	200	250	300	350	400	450	500	550	600	650	700	750	Maximum Concentration ppm
15 min	14,612	20.00	15.00	10.00	7.50	5.00	4.00	3.00	2.30	1.60	1.35	1.15	1.05	1.05	2,920
1 hr	3,628	20.00	15.00	10.00	7.10	4.10	3.15	2.65	2.10	1.75	1.40	1.00	0.90	0.80	1,982
2 hr	3,702	20.00	15.00	10.00	5.00	3.00	2.50	2.00	1.75	1.50	1.25	1.00	0.90	0.70	1,261
3 hr	3,758	20.00	15.00	10.00	5.00	2.20	2.00	1.60	1.25	0.85	0.80	0.55	0.50	0.50	1,238
4 hr	3,803	20.00	8.15	6.10	3.06	2.20	1.40	1.05	0.80	0.75	0.50	0.45	0.30	0.25	935
5 hr	3,841	20.00	10.00	5.00	2.75	1.75	1.25	1.00	0.75	0.55	0.40	0.30	0.25	0.15	935
6 hr	3,876	20.00	10.00	5.00	2.45	1.75	1.20	0.90	0.45	0.35	0.30	0.15	0.05	0.05	752
7 hr	3,901	20.00	10.00	5.00	2.15	1.40	1.00	0.55	0.30	0.20	0.10	0.05	0.00	0.00	662
8 hr	3,935	15.00	10.00	5.00	2.15	1.40	0.80	0.50	0.25	0.10	0.05	0.00	0.00	0.00	662
10 hr	3,988	15.00	10.00	5.00	2.05	1.20	0.55	0.25	0.10	0.05	0.00	0.00	0.00	0.00	576

Figure IX.B.5

UTAH STATE IMPLEMENTATION PLAN
CONTROL MEASURES FOR AREA AND POINT SOURCES
CARBON MONOXIDE
SECTION IX PART C

SECTION IX.C.l **Non-Attainment Areas**

National Ambient Air Quality Standards (NAAQS) have been established to protect public health and welfare. The health-related standards for carbon monoxide (CO) are nine parts per million over an eight-hour averaging period and 35 parts per million over a one-hour averaging period (not to be exceeded more than once per year). The one-hour standard has not been exceeded anywhere in the state. Measured exceedances of the eight-hour standard have been observed in the cities of Salt Lake, Ogden, Provo, and Bountiful. On March 3, 1978 the EPA designated these cities as non-attainment areas in accordance with the provisions of Section 107 of the Clean Air Act.

On December 21, 1983, the EPA redesignated Bountiful as an attainment area for CO based on eight quarters of ambient air data collected by the State which demonstrated attainment.

In response to new siting guidelines published by the EPA, CO monitoring sites were established in Salt Lake City on State Street between 200 and 300 South and on University Avenue in Provo between Center Street and 100 North. The data collected at the new sites showed concentrations higher than at the original sites, and were used in determining the design values for Salt Lake and Provo.

On December 19, 1984, the State was officially notified that EPA found substantial inadequacies in this SIP for Provo. Section IX.C.6 was added to this SIP in response to EPA's requirements and details those strategies which will be followed to provide for attainment of the CO standard in Utah County.

A summary of the measured exceedences of the eight hour standards in Ogden for the years 1980 and 1981 and in Salt Lake for 1982 is shown in Figure IX.C.1. High values such as these occur under adverse meteorological conditions (temperature inversions) which exist primarily from November through March.

Figure IX.C.1
8 Hour Carbon Monoxide Values Which Exceeded
the Primary NAAQS of 9 ppm (parts per million)

Ogden		Salt Lake City
1980	1981	1982
12	10	12
11		10
10		13
13		10
11		10
		11
		10
		11

IX.C.2 Carbon Monoxide Concentrations and Data Analysis

Because atypical meteorological conditions were observed in 1980 and 1981, the State determined that neither year could be considered representative for purposes of SIP planning. It was determined that an average of the second high concentration observed in these two years was appropriate for use as a design value for Ogden in this SIP (see the technical support document). For Salt Lake City, the design value used in this SIP was the second high State Street 8-hour value observed in 1982. The calculated design values for the areas of concern are as follows:

Salt Lake City 12.1 ppm
Ogden 10.5 ppm

The following necessary reductions in carbon monoxide were calculated for each area:

Salt Lake City 26%
Ogden 11%

IX.C.3 Carbon Monoxide Emissions

The most significant source of carbon monoxide emissions in the Wasatch Front is highway motor vehicles. However, annual emissions inventories reveal that space heating and industrial sources contribute measurable amounts to the total inventory.

Figure IX.C.2 shows the 1980 annual carbon monoxide emissions inventory for Salt Lake and Weber Counties.

Figure IX.C.2
Annual Carbon Monoxide Inventory (tons/year)

SOURCE CATEGORY	SALT LAKE COUNTY	WEBER COUNTY
Highway Vehicles	309,500	66,900
Off-Highway Vehicles	8,532	2,172
Other Transportation	5,346	1,955
Process Industries	304	1,005
Space Heating	15,659	3,654
Electric Power Generation	471	47
Forest Fires	1,908	1,259
TOTAL	341,720	76,992

Emissions of carbon monoxide and associated peak measured ambient levels tend to be concentrated in the urban cores of Salt Lake City and Ogden. Figure IX.C.3 shows typical winter daily inventories for these cities.

Figure IX.C.3
Annual CO Emissions (tons/day)

	SALT LAKE CITY (1982)	OGDEN (1980)
Highway Vehicles	316.88	107.2
Space Heating	27.5	11.0
Other Sources	10.6	6.4
TOTAL	354.98	124.6

IX.C.4 Control Strategy

The following control strategies are predicted to reduce emissions to the extent necessary to attain the National Ambient Air Quality Standards (NAAQS) for carbon monoxide:

- Federal Motor Vehicle Control Program (FMVCP)
- Automobile Inspection/Maintenance (I/M)
- Transportation Control Measures (TCM)

IX.C.4.a Federal Motor Vehicle Control Program

The FMVCP requires vehicle manufacturers to certify that new vehicles meet federal vehicle emission standards. As the older vehicles are replaced by newer vehicles with better controls, a dramatic reduction in vehicle emissions is being observed. In 1983 the "all modes" emission factor for 20 miles/hour was 111.16 grams per vehicle mile; in 1987 it is predicted to be reduced to 86.43 grams per vehicle mile. This represents a 22% reduction in CO emissions per vehicle mile.

IX.C.4.b Automobile Inspection/Maintenance

The EPA has determined that under the provisions of Section 172 of the Clean Air Act, an automobile inspection and maintenance program (I/M) is required as Reasonably Available Control Technology (RACT) for CO reduction in Salt Lake County and for ozone reduction in Salt Lake and Davis Counties to demonstrate attainment of the NAAQS. The I/M programs developed by both counties are designed to result in a 25% reduction of CO and a 25% reduction in HC as determined using Mobile2.

On July 21, 1983, the Utah State Legislature amended the State Motor Vehicle Code to include Sections 41-6-163.(5) and (6), Utah Code Annotated 1953, which gives county governments authority to implement I/M programs in counties affected by Section 172 of the Clean Air Act. The Statute requires that this program to be in place until the NAAQS are attained in the affected county. This Statute is contained in Section X, Appendix I.

The Salt Lake County Board of Health adopted an implementation schedule and regulations establishing an I/M program. The program was fully implemented by April 1, 1984. The regulations are contained in Section X, Appendix 7.

The Davis County Commission adopted an implementation schedule and a county ordinance establishing an I/M program. The program was fully implemented by April 1, 1984. The county ordinance is contained in Section X, Appendix 6.

IX.C.4.c <u>Transportation Control Measures</u>

The application of TCMs in the Salt Lake City and Ogden areas was developed by the Wasatch Front Regional Council in their document "Traffic Control Measures for the Wasatch Front Region" January 1982. The document is incorporated by reference into this State Implementation Plan and a brief summary is provided in Section XI, Appendix 2.

It was determined that the following control strategies were appropriate for Salt Lake and Ogden:

1. Salt Lake - Transit Improvements, Ridesharing, and Traffic Flow Improvements.

2. Ogden - Transit Improvements and Ridesharing.

(1) <u>Salt Lake City</u>

(a) <u>Transit Improvements</u>

The Utah Transit Authority proposes to increase the number of service miles in the Wasatch Front service area from 10.5 million in 1980 to 16 million by 1996. This is contingent upon their obtaining additional funding. This increase in service miles was predicted to result in a 2.1% reduction in region-wide carbon monoxide emissions.

(b) <u>Ridesharing Program</u>

A transportation brokerage is planned by the Wasatch Front Regional Council, Utah Transit Authority, and the Utah Energy Office which will coordinate individual transportation needs. The brokerage will concentrate its efforts on commuters. In addition, the program to build park and ride lots will be continued.

Major activities include:

1. Carpool and vanpool promotion and matching services for large firms. Including interest-free loans for van purchases.

2. Region wide carpool promotion and matching.

3. Dissemination of transit schedules.

4. Examination of commuter market needs.

This program was predicted to reduce emissions in Salt Lake City by 0.4%.

(c) <u>Traffic Flow Improvements</u>

The principal traffic flow improvement project is the computerization of traffic signals in Salt Lake City. This involves approximately 168 signals in an eight square mile area. It is anticipated that carbon monoxide emissions in Salt Lake City will be reduced by 0.5%, (from 260 to 259 T/D) as a result of this strategy.

(2) Ogden

(a) Transit Improvements

As discussed under Salt Lake City Transit Improvements, region wide carbon monoxide emissions are expected to be reduced 2.l% as a result of improved transit.

(b) Ridesharing Program

Ogden will participate in the transportation brokerage discussed in connection with the Salt Lake City Ridesharing Program. It is estimated that carbon monoxide emissions within Ogden City were reduced by 0.3% as a result of this program.

IX.C.4.d Other Strategies

Other strategies which have not been studied by either MAG or WFRC include: (1) control of fleet operations; (2) retrofit programs; (3) extreme cold starts. Comments on these additional strategies are:

(1) Control of Fleet Operations

For several years, Mountain Fuel Supply has conducted studies on the feasibility of converting motor vehicles to propane. The Department of Health participated in these studies and has encouraged fleet owners to convert to propane. The use of propane results in a reduction of automobile emissions if the system is properly tuned and maintained, and these conversions will continue to be encouraged.

(2) Retrofit Programs

As of this time, EPA has not certified any retrofit devices which reduce emissions in a feasible manner. The Air Conservation Committee will continue to monitor the EPA efforts in this area.

(3) Extreme Cold Starts

The winters in Utah are comparatively mild; therefore, strategies to control emissions from extreme cold starts are inappropriate for this area.

IX.C.5 Demonstration of Attainment and Reasonable Further Progress

IX.C.5.a. Salt Lake City

From Section IX.C.3, the Salt Lake City 1982 typical winter weekday inventory of CO was 354.98 tons/day.

From Section IX.C.2, the necessary reduction to attain the 9 ppm level was 26%.

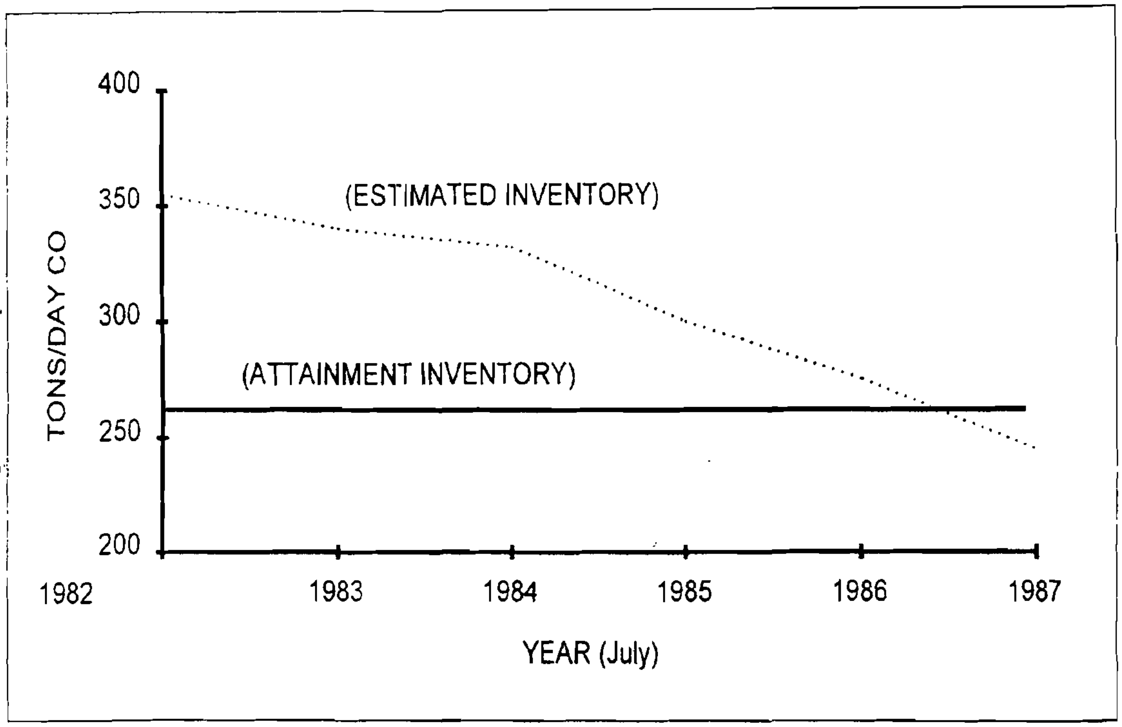
Therefore the attainment inventory is:

354.98 tons/day (1 - 0.26) = 262.69 tons/day

The following table shows the effective winter weekday emission inventory for downtown Salt Lake City on the date when it is predicted to reach this level. The values are in tons of carbon monoxide per day.

	1982	Nov 15, 1986
Highway Vehicles	316.88	247.7
Space Heating	27.5	27.5
Other Sources	10.6	10.6
Total	354.98	285.8

Figure IX.C.4 illustrates reasonable further progress.



400
350
300
250
200
TONS/DAY CO
(ESTIMATED INVENTORY)
(ATTAINMENT INVENTORY)
1982
1983
1984
1985
1986
1987
YEAR (July)

FIGURE IX-C.4

IX.C.5.b. Ogden

From Section IX.C.3 the 1980 Ogden City typical winter weekday inventory was 124.6 tons/day.

From Section IX.C.2 the necessary reduction to attain the 9 ppm level was 11%.

Therefore the attainment inventory is:

$$124.6 \text{ tons/day } (1 - 0.11) = 110.9 \text{ tons/day.}$$

The following table shows the dates on which the effective winter weekday emission inventory for downtown Ogden is predicted to reach this level. The values are in tons per day of carbon monoxide:

	1980	**July 1, 1982**
Highway Vehicles	107.2	93.5
Space Heating	11.0	11.0
Other Sources	6.4	6.4
Total	**124.6**	**110.9**

Figure IX.C.5 illustrates reasonable further progress.

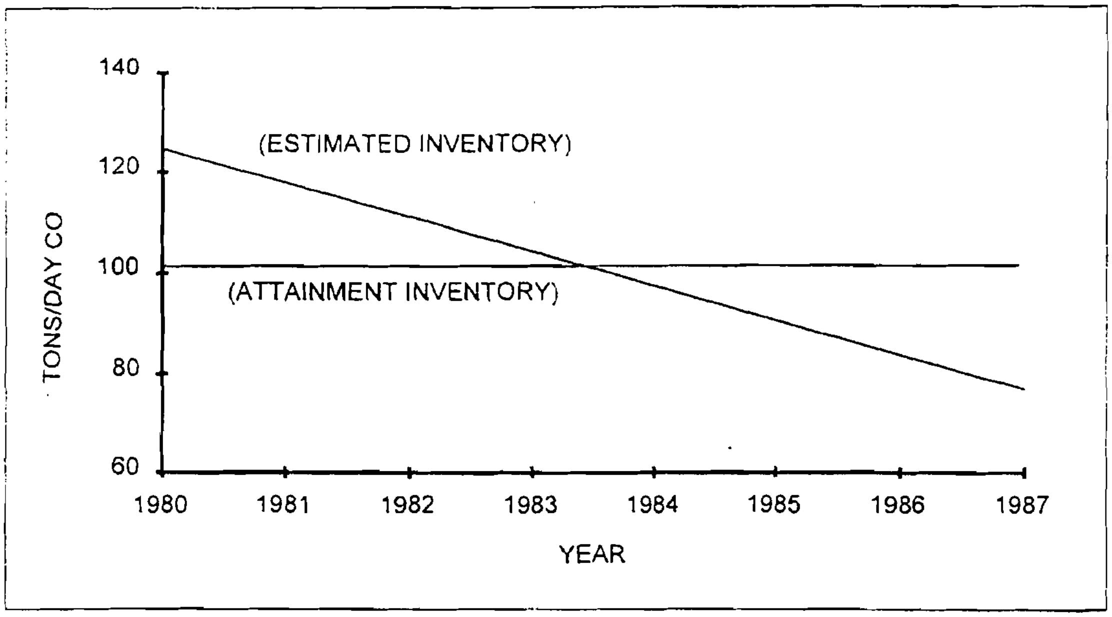

140
120
100
80
60
TONS/DAY CO
(ESTIMATED INVENTORY)
(ATTAINMENT INVENTORY)
1980
1981
1982
1983
1984
1985
1986
1987
YEAR

FIGURE IX-C.5

IX.C.6 <u>Provo</u>

This section IX.C.6 has been replaced with subsequent IX.C.6 section approved on November 2, 2005 (70 FR 66264). The new IX.C.6 is contained in a separate entry in this database. See April 18, 2007 (72 FR 19383) correction notice.

'e IX.C.5
BASE-YEAR (1990) CO EMISSIONS INVENTORY
OGDEN

AREA SOURCES		Tons/Year	Tons/Day
Stationary External Combustion	Orchard Heaters	N/D	N/D
	Woodburning/Fireplaces	932.84	5.42 *
	Coal - Residential	5.44	Neg
	Coal - Commercial	.60	Neg
	Coal - Industrial	28.85	Neg
	Gas - Residential	.26	Neg
	Gas - Commercial	Neg	Neg
	Gas - Industrial	19.98	.04
	Oil - Residential	.25	Neg
	Oil - Commercial	.29	Neg
	Oil - Industrial	14.28	.05
Waste Disposal, Treatment, and Recovery	Incineration - Com	19.26	.05
	Incineration - Ind	14.05	.04
Miscellaneous Sources	Forest Fires	N/D	N/D
	Fire-fighting Training	Neg	Neg
	Structural Fires	.08	Neg
	Prescribed Burning/ Slash Burning/ Agricultural Burning	N/D	N/D
	Open Burning/Detonation	1.69	N/D
	Aircraft/Rocket Engine Firing/Testing	3.21	Neg
	Charcoal Grilling	N/I	N/I
MOBILE			
On-Road	On-Road	22356.48	67.80
Non-Road	Aircraft	321.10	.52
	Railroads	26.46	.07
	Misc Non-road Equipment	361.10	.30
POINT SOURCES		N/D	N/D
TOTAL CO EMISSION OGDEN, UTAH		24106.22	74.29

PT/S =Reported as a point source. N/A = Not applicable.
N/I= No info available N/D =Negative declaration Neg =Negligible amount.
Number may vary slightly from report due to rounding. Numbers may not add due to rounding.

b. Required by 1990 Clean Air Act Amendments

Table IX.C.4 is a summary of the 1990 base-year annual inventory for Salt Lake City; Table IX.C.5 shows comparable data for Ogden. Figure IX.C.1 and Figure IX.C.2 summarize the daily and annual emissions inventory for Salt Lake City, respectively. Figure IX.C.3 and Figure IX.C.4 summarize the daily and annual emissions inventory for Ogden, respectively. No major point sources of 100 tons/year of CO were identified in Salt Lake City or Ogden. The complete inventory and the required documentation is contained in the Technical Support Document.

Table IX.C.4
BASE-YEAR (1990) CO EMISSIONS INVENTORY
SALT LAKE CITY

AREA SOURCES		Tons/Year	Tons/Day
Stationary External Combustion	Orchard Heaters	N/D	N/D
	Woodburning/Fireplaces	2334.48	13.56
	Coal - Residential	13.61	Neg
	Coal - Commercial	1.51	.01
	Coal - Industrial	.07	Neg
	Gas - Residential	28.21	Neg
	Gas - Commercial	Neg	Neg
	Gas - Industrial	21.83	.02
	Oil - Residential	.62	Neg
	Oil - Commercial	.72	Neg
	Oil - Industrial	35.74	.13
Waste Disposal, Treatment, and Recovery	Incineration - Com	48.2	.13
	Incineration - Ind	26.16	.07
Miscellaneous Sources	Forest Fires	N/D	N/D
	Fire-fighting Training	Neg	Neg
	Structural Fires	.2	Neg
	Prescribed Burning/ Slash Burning/ Agricultural Burning	N/D	N/D
	Open Burning/Detonation	N/D	N/D
	Aircraft/Rocket Engine Firing/Testing	19.6	.06
	Charcoal Grilling	N/I	N/I
MOBILE SOURCES			
On-Road	On-Road	63249.42	228.78
Non-Road	Aircraft	1959.58	5.75
	Railroads	68.22	.19
	Misc Non-road Equipment	2285.06	1.92
POINT SOURCES		N/D	N/D
TOTAL CO EMISSIONS - SALT LAKE CITY, UTAH		70093.23	250.62

PT/S =Reported as a point source. N/A =Not applicable.
N/I= No info available N/D =Negative declaration. Neg =Negligible amount.
Number may vary slightly from report due to rounding. Numbers may not add due to rounding.

Table IX.C.10
BASE-YEAR (1990) CO EMISSIONS INVENTORY
UTAH COUNTY

Area Sources		Tons/Year	Tons/Day
Stationary External Combustion	Orchard Heaters	N/D	N/D
	Woodburning/Fireplaces	3847.44	22.35
	Coal - Residential	815.64	3.80
	Coal - Commercial	2.51	Neg
	Coal - Industrial	PT/S	PT/S
	Gas - Residential	80.28	0.29
	Gas - Commercial	12.36	0.05
	Gas - Industrial	52.51	0.26
	Oil - Residential	1.03	Neg.
	Oil - Commercial	1.18	Neg.
	Oil - Industrial	14.72	0.05
Waste Disposal	Incineration - Com/Ind	130.07	0.36
Miscellaneous Sources	Forest Fires	71.39	N/D
	Fire-fighting Training	Neg.	Neg.
	Structural Fires	0.32	Neg.
	Prescribed Burning/Slash Burning/Agricultural Burning	3396.47	N/D
	Open Burning/	0.54	N/D
	Detonation	5.90	0.02
	Aircraft/Rocket Engine Firing & Testing	2.79	0.01
	Charcoal Grilling	N/I	N/I
Mobile Sources			
On-Road	On-Road	120522.05	353.23
Non-Road	Aircraft	278.51	0.71
	Railroads	213.89	0.59
	Misc Non-Road Equipment	3746.00	3.15
Point Sources			
Geneva Steel		35849.31	108.14
Pacific States Cast Iron Pipe Company		7278.62	37.10
Total CO Emissions - Utah County		176323.53	530.11

PT/S =Reported as a point source. N/A =Not applicable.
N/I= No info available N/D =Negative declaration Neg =Negligible amount.
Number may vary slightly from report due to rounding. Numbers may not add due to rounding.

CARBON MONOXIDE PROVISIONS

FOR PROVO

Section IX, Part C.6

Adopted by the Air Quality Board
March 31, 2004

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

IX.C.6 Carbon Monoxide Provisions for Provo

a. INTRODUCTION

The State of Utah requests that the U.S. Environmental Protection Agency (EPA) approve a new attainment demonstration and maintenance plan for Provo and redesignate Provo to attainment status for the National Ambient Air Quality Standards (NAAQS) for carbon monoxide (CO). Provo has not violated the standard since 1993, and with the approved attainment demonstration and maintenance plan, the area is now eligible for redesignation. Provo refers to the area within the geographic boundaries of the city of Provo, the area addressed by this Plan.

The Attainment Demonstration, which is being submitted for inclusion in Utah's federally enforceable State Implementation Plan (SIP), demonstrates that Provo had attained the NAAQS for carbon monoxide by the year 2000.

The Maintenance Plan, which is being submitted for inclusion in Utah's federally enforceable SIP, provides for maintenance of the NAAQS standard for carbon monoxide in Provo through the year 2015.

(1) National Ambient Air Quality Standards for Carbon Monoxide

The National Ambient Air Quality Standards (NAAQS) for carbon monoxide are found in 40 CFR Part 50.8. The EPA has promulgated two standards for carbon monoxide:

- The eight-hour non-overlapping 9 ppm average not to be exceeded more than once per year. The rounding convention in the standard specifies that values of 9.5 ppm or greater exceed the standard. High values that occur within eight hours following the first one are exempted, using "non-overlapping averages."

- The one-hour concentration of 35 ppm is not to be exceeded more than once per year. This standard has never been violated in Utah.

A violation occurs when two or more exceedances of the 8-hour standard are recorded at the same monitoring station during a calendar year. To be in attainment, an area must meet the NAAQS for two consecutive years and carry out air quality monitoring during the entire time.

The primary source of CO is the incomplete combustion of fuels such as gasoline. Local weather conditions and the number of vehicles and vehicle miles traveled in the area influence CO levels. The largest emissions contribution comes from on-road motor vehicles. Other significant CO sources may include woodburning stoves, incinerators and industrial sources.

(2) Provo Attainment/Maintenance Area

Provo is situated at the base of the Wasatch Mountains in north central Utah about 50 miles south of Salt Lake City, and is the seat of Utah County. In 2003, about 105,000 people lived in Provo. Population in Provo increased more than twenty percent during the 1990s, but has remained relatively stable over the past three years. Because Provo is nearly surrounded by mountains and other cities, not much growth within Provo's municipal boundaries is likely to occur in future years.

Provo occasionally encounters strong wintertime inversions that can trap pollutants, including carbon monoxide, in the valley. As pollutants are emitted into the stagnant air, concentrations may increase and in the past have exceeded the 8-hour national air quality standards.

(3) Provo Carbon Monoxide Designation History

During the SIP development process in 1993-94, it was determined through modeling that the only areas in the county where violations were potentially occurring were in Provo and Orem. The CO SIP that was submitted to EPA for approval on July 11, 1994, classified Provo and Orem as a moderate non-attainment area for CO with a design value of 15.8 ppm and a mandatory attainment date of December 31, 1995. On September 20, 2002 (67 FR 59165), EPA published a determination that the Provo nonattainment area had attained the NAAQS for CO by December 31, 1995. EPA never approved the 1994 SIP submittal, although they did approve the vehicle Inspection and Maintenance (I/M) program and the 2.7% and 3.1% oxygenated fuels programs.

Projections of vehicle miles traveled (VMT) were provided for the 1994 CO SIP submittal by the local metropolitan planning organization, Mountainland Association of Governments (MAG), and the Utah Department of Transportation (UDOT) to demonstrate that the state was making reasonable further progress towards attaining the NAAQS. MAG estimated that the VMT would be expected to grow at a rate of about 4.1% across the Utah County modeling domain, compounded annually from 1992 through 1996. In the 1994 CO SIP submittal, the state committed to provide EPA with a report of actual VMT for the area of nonattainment for the preceding year by September 30 of each year. In 1995, the actual VMT figures exceeded the VMT forecasts and the contingency measures were triggered in 1996, increasing the oxygen content of gasoline sold in Utah County from 2.7% to 3.1%. In September 2001, the oxygenate concentration under State law was reduced to 2.7% after MOBILE6 modeling runs demonstrated that the NAAQS could be met with the lower concentration of oxygenate; EPA approved the revision on September 20, 2002 (67 FR 59165).

With the submittal of this revised Attainment Demonstration and Maintenance Plan, Utah withdraws its submittal of the 1994 Attainment Demonstration and SIP Revision. However, for informational purposes, the 1994 submittal is contained in Volume 1, Section 2 of the TSD and is referred to frequently in this document.

b. CARBON MONOXIDE MONITORING NETWORK

(1) Attainment of the Carbon Monoxide Standard

The current carbon monoxide ambient air monitoring network in the Provo area consists of two State and Local Air Monitoring Stations (SLAMS) in Provo that are operated by the UDAQ Air Monitoring Center (AMC). During the development of the 1994 SIP, modeling demonstrated a potential hot spot in south Orem, and a monitoring site was also established there to verify attainment of the NAAQS in the area; however, no exceedances of the NAAQS were ever monitored at the South Orem monitoring site.

The monitoring sites are listed in Table 1, and Figure 1 on the following page shows the geographical distribution of the monitors.

Table 1. Monitoring Site Locations

Site	Site Code	Site Address	AIRS Code
North Provo	NP	1355 N. 200 W. Provo	49-049-0002
University Ave. #3	U3	363 N. University Ave., Provo	49-049-0005
South Orem	SO	1580 S. State St. Orem	49-049-5005

With the implementation of emission control programs aimed at reducing automobile, truck and wood burning emissions, carbon monoxide concentrations decreased. In 1983 (54 FR 9796), the EPA approved the first CO SIP for Utah County as required by the 1977 Amendments to the Clean Air Act. This SIP included the first vehicle inspection and maintenance program for Utah County. On November 6, 1991, EPA the designation of Provo as nonattainment for CO with a "moderate" classification and a design value greater than 12.7 ppm. The remainder of Utah County was designated as unclassifiable/attainment.

During the SIP development process in 1994, it was determined through modeling that the only areas in the county where violations could be occurring were in Provo and Orem. In response to that modeling, a monitor was installed in Orem, but no violations were found there. The CO SIP that was submitted to EPA for approval on July 11, 1994, classified Provo and Orem as a moderate non-attainment area for CO with a design value of 15.8 ppm and a mandatory attainment date of December 31, 1995. However, EPA did not approve that SIP submittal, and therefore the federally-defined nonattainment area is Provo only. On September 20, 2002 (67 FR 59232), EPA published a determination that the Provo nonattainment area had attained the NAAQS for CO by December 31, 1995.

Oxygenated gasoline at 2.7% was introduced in Utah County in November 1992. As noted in Subpart (3) above, the percentage oxygenate was increased to 3.1% in 1996 due the failure of Utah County to implement the federally-required test-only vehicle emission inspection and maintenance program. Oxyfuel returned to 2.7% in 2001 under state law, and EPA approved the revision on September 20, 2002 (67 FR 59165).

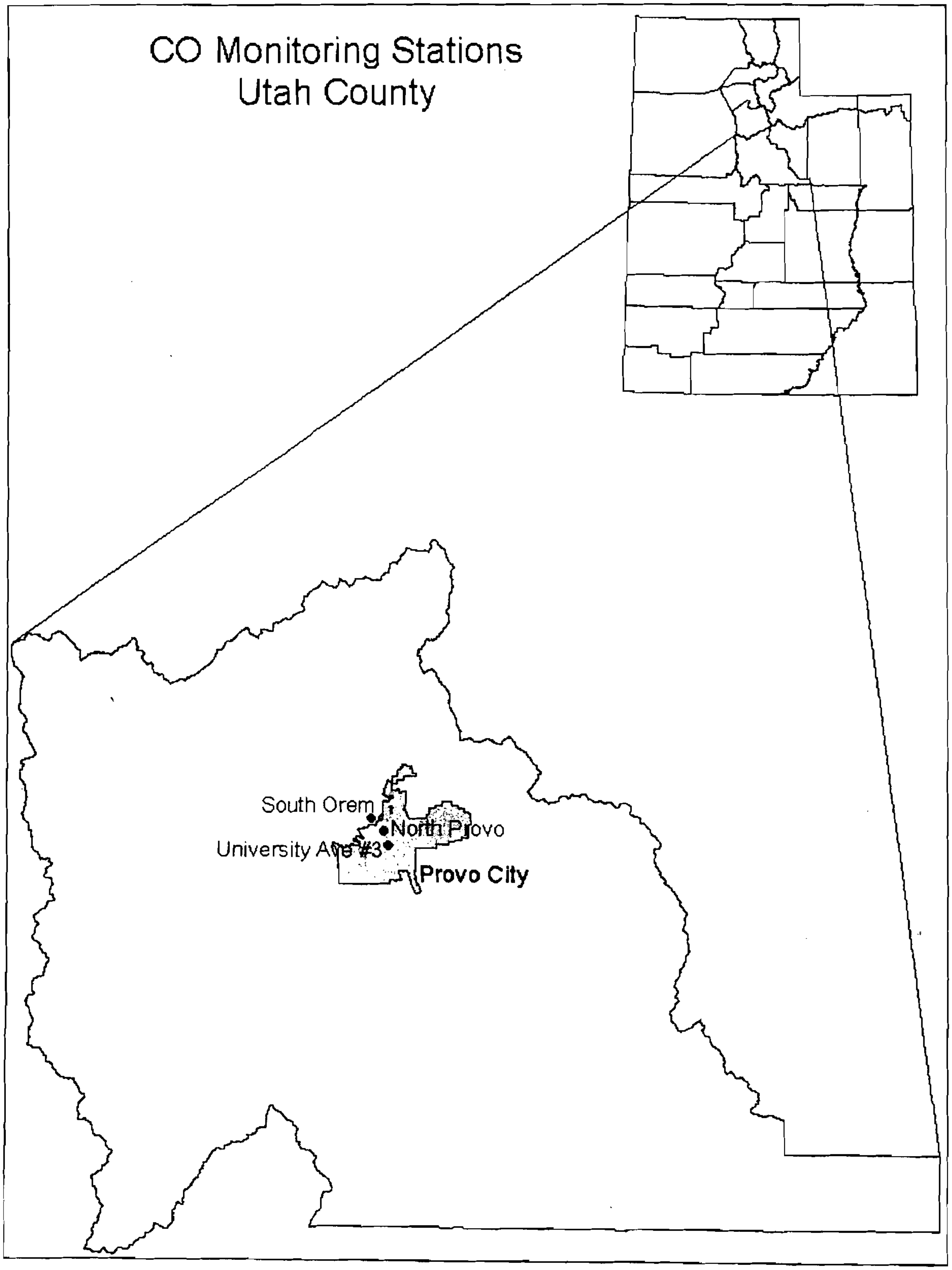
The last recorded violation of the eight-hour standard occurred in 1993. Provo has never exceeded the 1-hour NAAQS for CO.

(2) Monitoring Results and Attainment Demonstration

The 1994 SIP Submittal contained in Volume 1, Section 2 of the TSD contains a discussion and analysis of the monitoring data used to classify Provo as a nonattainment area.

Since the 1994 CO SIP submittal, the monitoring data for the area shows two exceedances of the CO standard. One occurred in 1994 at the University Avenue #2 site and the second occurred in 1996 at the University Avenue #3 site. (The monitoring site was moved one block in 1996.) Exceedances of the CO standard have not occurred since 1996 and the magnitudes of the eight-hour concentrations have dramatically decreased. The improvement is attributed to a combination of newer, cleaner operating cars and the implementation of control strategies. Although vehicle miles traveled (VMTs) are increasing, no exceedances of the CO standard have been monitored. As stated above, no exceedances of the CO NAAQS have ever been recorded at the South Orem monitoring site.

Figure 1. Utah County's Carbon Monoxide Monitors



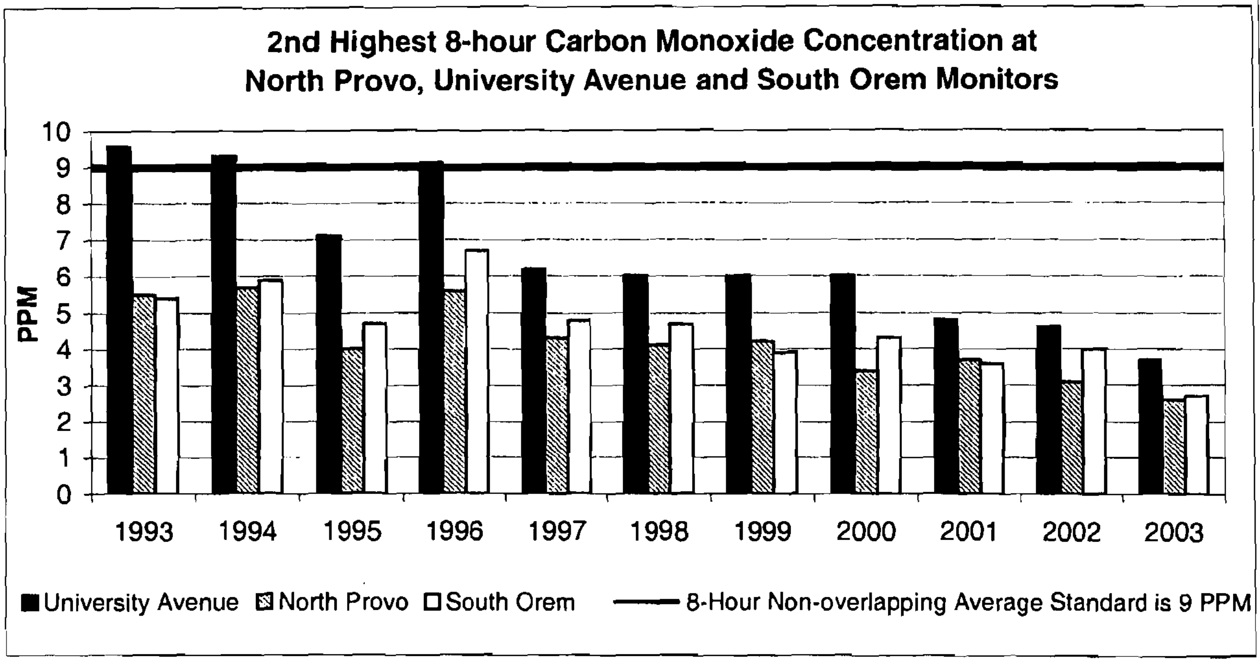
Monitored data is found in EPA's Aerometric Information and Retrieval System (AIRS) database. Table 2 displays the monitored high and 2nd-high values at the CO monitors in Provo from 1994 through 2001. Figure 2 is a graph of the history of CO second-high eight-hour average concentrations and displays a comparison of the measured concentrations with the NAAQS.

Table 2. **1st and 2nd High 8-hour CO Concentrations (ppm) at Utah County Monitoring Stations**

	University Avenue #2		North Provo		South Orem	
	1st High	2nd High	1st High	2nd High	1st High	2nd High
1994	9.9	9.3	6.1	5.7	6.0	5.9
1995	7.6	7.1	4.4	4.0	5.3	4.7
1996	10.2	9.1	6.7	5.6	7.6	6.7
	University Avenue #3*		North Provo		South Orem	
	1st High	2nd High	1st High	2nd High	1st High	2nd High
1995	7.2	6.3	4.4	4.0	5.3	4.7
1996	10.2	8.0	6.7	5.6	7.6	6.7
1997	6.6	6.2	4.4	4.3	5.5	4.8
1998	6.9	6.0	4.1	4.1	4.9	4.7
1999	6.9	6.0	4.9	4.2	3.9	3.9
2000	6.6	6.0	3.6	3.4	4.3	4.3
2001	7.5	4.8	4.4	3.7	3.6	3.6
2002	5.0	4.6	3.6	3.1	5.4	4.0
2003	4.1	3.7	3.0	2.6	2.8	2.7

* The monitoring site at 240 University Avenue (#2) was replaced with a monitor at 363 University Avenue (#3).

Figure 2. 2nd Highest 8-hour Carbon Monoxide Concentration at the Provo & South Orem Monitors



(3) Quality Assurance Program

Carbon monoxide data for Provo and Utah County have been collected and quality-assured in accordance with 40 CFR, Part 58, Appendix A, EPA's "Quality Assurance Handbook for Air Pollution Measurement Systems, Vol. 11; Ambient Air Specific Methods." All of the monitoring data for the State of Utah is contained in the AIRS database. In addition, DAQ has verified that the integrity of the air quality monitoring network has been preserved. The precision and accuracy results for the Provo area monitoring network are summarized in the technical support document (Volume 12, Section 4) for this redesignation request and maintenance plan. The calculated 95 percent probability limits for the precision checks and accuracy audits demonstrate that the sites were meeting acceptable quality assurance limits for repeatability and accuracy.

(4) Monitoring Network

Information concerning CO monitoring in Utah is included in the Monitoring Network Review (MNR). Since the early 1980's, the MNR has been updated annually and submitted to EPA for approval. EPA personnel have concurred with the annual network reviews, and have agreed that the network remains adequate.

(5) Ongoing Review of Monitoring Sites

The State commits to continue operating the existing CO monitoring sites according to the requirements of 40 CFR Part 58 and will gain EPA approval before any changes are made to the Utah County CO monitoring network. The State will reevaluate the site location annually to determine whether new monitoring sites are needed or whether existing monitoring sites should be removed or relocated.

c. ATTAINMENT PLAN

(1) Required Components of an Attainment Demonstration

The Clean Air Act in Section 187(a) sets forth the requirements for a SIP for carbon monoxide nonattainment areas that are designated as moderate under Section 186(a)(1). These requirements are set forth in Table 3.

Table 3. Requirements of a State Implementation Plan for Moderate Carbon Monoxide Nonattainment Areas

Category	Requirement	Reference	Addressed in Part
Base-Year Inventory	The SIP must include an inventory of actual emissions from all sources.	CAA 187(a)(1), CAA 172(c)(3)	IX.C.6.c(2)-(3)
VMT Forecast	For any area with a design value >12.7 ppm at the time of classification, the SIP shall include a forecast of vehicle miles traveled in the nonattainment area for each year prior to the year in which attainment is forecast. Annual updates shall be submitted to EPA.	CAA 187(a)(2)(A)	Volume 1, Section 2, TSD – 1994 SIP Submittal – Table IX.C.14
Contingency Measures	For any area with a design value >12.7 ppm at the time of classification, the SIP shall provide for implementation of specific contingency measures if the VMT forecast is exceeded or the area fails to attain the standard by the standard attainment date. Such measures shall take effect without further action by the Administrator of EPA or the State.	CAA 187(a)(3)	IX.C.6.c(5)
Basic I/M	The SIP must include a basic inspection and maintenance program.	CAA 187(a)(4), CAA 182a(a)(2)(B)	IX.C.6.c(4)(c)
Inventory Every 3rd Year	The SIP must include a commitment to submit an inventory by Sept 30, 1995, and every third year thereafter until the area is redesignated to attainment.	CAA 187(a)(5), CAA 187(a)(1), CAA 172(c)(3)	IX.C.6.c(4)(d)
Enhanced I/M	For any area with a design value >12.7 ppm at the time of classification, the SIP shall provide for implementation of an enhanced vehicle emissions inspection and maintenance program	CAA 187(a)(6), CAA 182a(c)(3)	IX.C.6.c(4)(c)
Attainment Demonstration and Control Strategies	A SIP must be submitted by November 15, 1992, showing that the area will attain the standard by the attainment date of December 31, 1995.	CAA 187(a)(7)	IX.C.6.c(4)

(2) Monitoring Data Analysis and Design Value Determination

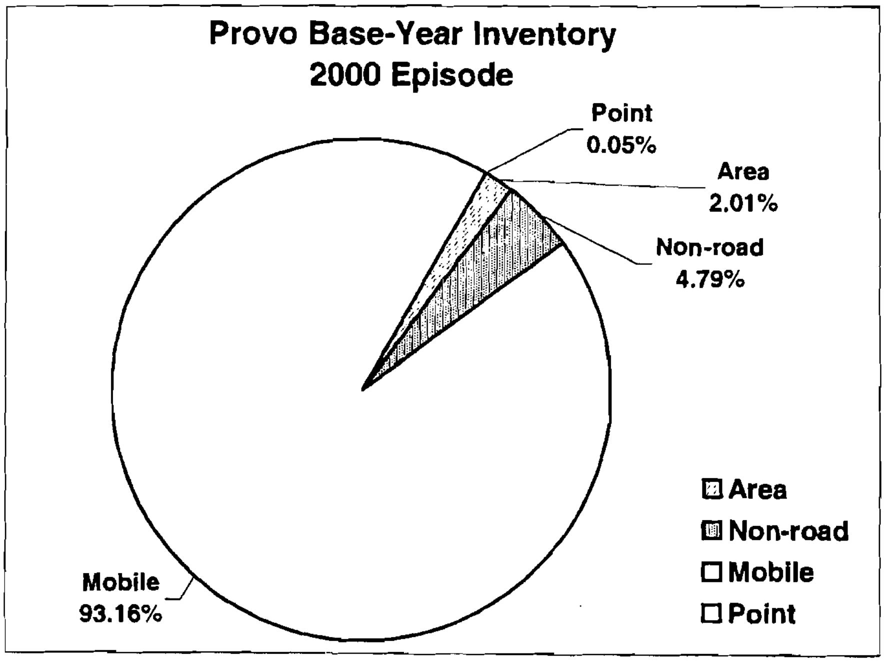
The monitoring data analysis used to establish the Design Value is contained in the 1994 SIP Submittal contained in Volume 1, Section 2 of the TSD.

(3) Attainment (Base-Year) Emissions Inventory

The State is basing this attainment demonstration on data for calendar year 2000, and specifically on the winter-time episode when the high value for the year occurred. The selection of that episode is contained in the Episode Selection Document contained in Volume 12, Section 4.b.ii of the TSD. The following is a discussion of the emissions inventory used for that episode. This data was collected and analyzed according to the Inventory Preparation Plan (IPP) contained in Volume 9, Section 3.a of the TSD.

The emissions inventory identifies CO emissions from different sources in Provo. Maximum CO concentrations occur during winter temperature inversions; therefore the inventories used in this attainment demonstration reflect emissions on an average winter day. Mobile sources generate approximately 93 percent of the carbon monoxide (CO) emitted in Provo. Figure 3 illustrates the distribution of daily CO emissions in Provo for the attainment episode in 2000.

Figure 3. Provo 2000 Base-Year Episodic Inventory



The attainment year episodic emissions inventory is divided into three major sections: point sources, area sources, and mobile sources. A discussion of each of these three sections follows. Table 4 below shows peak CO daily emissions from each category in tons/winter day for Provo.

Table 4. 2000 Provo Attainment-Episode Inventory

Provo (Tons per Day)	2000
Mobile	59.44
Point	0.03
Area	1.28
Non-Road	3.05
Total	63.80

(a) Point Sources

Provo is a moderate CO nonattainment area, and there are no major point sources of CO within the municipal boundaries. During the development of the 1994 SIP submittal, two major sources of CO existed in Utah County outside the Provo municipal boundaries. That version of the SIP, contained in Volume 1, Section 2 of the TSD, contains an analysis demonstrating that those two sources do not have a significant impact on the nonattainment area. Because Provo was classified as a moderate CO nonattainment area, hotspot modeling for point sources using ISCST3 is not required in the Clean Air Act. However, emissions from all point sources within the modeling domain were input into the UAM-AERO model, and the mobile modeling results from CAL3QHCR were paired in time and space with the output from UAM-AERO.

(b) Area Sources

The area source inventory for Provo was derived from the UAM-AERO model using a grid-based allocation of emissions within the Provo municipal boundaries.

(c) Mobile Sources

Mountainland Association of Governments (MAG) provided the mobile source inventory using the MOBILE6.1 emission model and applicable transportation data. The analysis is found in Volume 10, Section 3.b.i, Provo/Utah County On-Road Mobile Sources, of the TSD.

(4) Attainment Demonstration

(a) Modeling Analysis

The modeling analysis using UAM-AERO and CAL3QHCR for the nonattainment area was done as described in the Modeling Protocol contained in Volume 12, Section 4.b.i of the TSD.

The technical analysis of CO concentrations in the Provo/Orem area completed in 1994 and contained in the 1994 SIP submittal in Volume 1, Section 2 of the TSD concluded that the CO problem was occurring primarily at one particular intersection on University Avenue in Provo. The application of source specific modeling of two large industrial sources, Geneva Steel and Pacific States Cast Iron Pipe, indicated that the elevated CO concentrations at specific intersections were not influenced by emissions from these sources. In addition, detailed meteorological analysis of both the observation record and prognostic modeling showed that very specific meteorological conditions accompanied elevated CO concentrations. An analysis of the CO monitoring database for the Provo/Orem area, combined with the meteorological record over the last decade, indicates that the conclusions reached in the 1994 analysis--i.e., that the CO problem occurred primarily at a single intersection in Provo, and that elevated concentrations at specific intersections are not influenced by emissions from point sources--continue to be valid today. Section 2 of the Episode Selection Document describes in detail the analysis used to select the base year modeling episodes, and the 2000 episode was used as the attainment year for this attainment demonstration. Detailed discussion of episode selection is found in the Episode Selection Document in Volume 12, Section 4.b.ii of the TSD.

(b) Episode Modeling

The CO Modeling (Volume 12, Section 4.a, UAM-CAL3QHCR Modeling, of the TSD) describes in detail the suite of models used for this analysis. A combination of the CAL3QHCR traffic model and the UAM-AERO regional model were used to capture the effects of the local contribution to CO from automobiles at intersections and the more generalized contribution to background CO. As required by EPA, the intersections studied included the three with the highest VMT counts and the three with the lowest level of service (LOS) in the nonattainment area. The results of these two models are summed to derive an estimate of the total CO concentration that can be expected at "hot spot" intersections where CO is expected to be the highest.

The episode was modeled with the control strategies in place at the time, including use of oxygenated gasoline in Utah County. Since the selected intersections showed no exceedance of the CO NAAQS, any intersections with lower traffic volumes and less congestion would have less ambient air impacts. There were no modeled exceedances of the CO NAAQS within the modeling domain. Therefore, attainment of the carbon monoxide standard is demonstrated for the year 2000. Further information about the episodic modeling strategy and results is available in the Modeling Protocol contained in Volume 12, Section 4.b.i of the Technical Support Document. Results are displayed in Table 5.

TABLE 5. 2000 EPISODE: 8-HOUR MAXIMUM CO CONCENTRATIONS (PPM)

Location	Concentration
University Ave University Parkway	8.3
1230 North University Ave	7.1
1230 North 500 West	7.7
500 West Center St.	8.5
500 North University Ave & Center St.	8.6

(c) Control Strategies to Attain the NAAQS

(i) Oxygenated Gasoline Program

The requirements for the Oxygenated Gasoline Program in effect in Utah County in 2000 and used to attain the NAAQS provide:

- a winter season control period from November 1 through the end of February each year; and
- addition of a minimum of 3.1% oxygen content by weight to gasoline sold in Utah County during the control period.

(ii) Gasoline Vehicle Emissions Inspection and Maintenance (I/M) Program

Model year 1968 through 1995 cars and trucks fueled with gasoline, propane and natural gas and owned by residents of Utah County, including Provo, are subject to an annual, two-speed idle program. Vehicles 1996 and newer undergo On-Board Diagnostics (OBD) inspection. The local Utah County Health Department, under the direction of the Utah County Commission, manages the program, and the program is primarily a decentralized, test-and-repair program. The program has an active covert compliance program to minimize potential fraudulent testing. While the county will issue waivers under limited circumstances, these are seldom granted and require a reduction in carbon monoxide emissions. EPA has verified that Utah County's I/M program is equivalent to a test-only program (67 FR 57744, September 12, 2002).

Students attending colleges and universities in the area are required to comply with vehicle emission testing prior to registering their vehicles on campus, whether or not they are domiciled in Utah County.

Utah County also maintains a limited remote sensing capability. While not mandated by the SIP, this capability was used to help quantify program effectiveness and may enhance future program flexibility.

A complete description of the Utah County I/M program is found in Section X, Parts A and D, of the Utah State Implementation Plan.

(A) Basic Inspection and Maintenance Program

As a result of the Clean Air Act Amendments of 1990, EPA promulgated minimum requirements for Basic and Enhanced Inspection and Maintenance (I/M) programs in 40 CFR Part 51. Under Section 182 of the Act, the state was required to implement a vehicle emissions inspection and maintenance program in Utah County that is at least as effective as the EPA's Basic Performance Standard. The State added Section X, Basic Automotive I/M, to the Utah SIP to meet those requirements.

(B) Enhanced Inspection and Maintenance Program

At the time the CO SIP was developed in 1994, EPA assumed only 50% credit for a decentralized test-and-repair I/M program. In order to qualify for 100% credit, an enhanced vehicle emissions inspection and maintenance program was identified as a control strategy in the SIP with an implementation date of July 1, 1995. On January 25, 1995, the Utah County Commissioners adopted Ordinance No. 1995-02, which specified the requirements of the Enhanced and Basic Vehicle Emission Inspection and Maintenance Program Rules and Regulations. The ordinance also specified that the rules and regulations would be implemented only if the County Commission was unable to implement equivalent emission reduction strategies as required by the Carbon Monoxide SIP.

Utah County pursued approval of equivalent emission reduction strategies by demonstrating its decentralized I/M program with enhancements would provide equal or greater emission reductions than a centralized test-only program. Following the provisions of Section 348 of the National Highway System Designation Act of 1995 (NHSDA), Utah County performed additional testing and analysis using methodology developed by the Environmental Council of the States (ECOS), State and Territorial Air Pollution Program Administrators (STAPPA) and EPA I/M Workgroup in response to the NHSDA requirements.

Utah County's NHSDA analysis was submitted to EPA on May 27, 1999. On September 12, 2002 (67 FR 57775), EPA published approval of the Utah County I/M program, including approval of the demonstration of full emissions reduction credit for the program. This allowed Utah County to claim 100% emissions test-only credit for its I/M program and to meet the federal requirements, as modified by the NHSDA for an enhanced program.

(iii) Wood-burning Controls

Controls on wood-burning stoves and fireplaces were included in the 1994 SIP revision; complete details of the program are found in the 1994 SIP submittal in Volume 1, Section 2 of the TSD at IX.C.6(j)(2)(c) and in R307-302-3. "Red" (mandatory no-burn) status is called when ambient CO concentrations reach 6.0 ppm and when forecasted meteorological conditions indicate that carbon monoxide levels may continue to rise. There were four red days for carbon monoxide in Provo-Orem in the 1995-96 winter season, but none have been called since that time.

(d) Tri-Annual Emissions Inventory

The state will continue to upload the tri-annual emissions inventory into the National Emissions Inventory database as required by the Consolidated Emissions Reporting Rule (67 FR 39602, June 10, 2002).

(5) Contingency Plan

The 1994 SIP at IX.C.6.f, included in Volume 1, Section 2 of the TSD, identified increasing the oxygenate in gasoline sold in Utah County in the winter season from 2.7% to 3.1% as the contingency measure to be implemented if the projected VMTs were exceeded, or if Utah County failed to implement an enhanced inspection and maintenance program by July 1, 1995.

d. MAINTENANCE PLAN

(1) Required Components of a Maintenance Plan and Redesignation Request

Section 107(d)(3)(D) and (E) of the Clean Air Act define the criteria an area must meet before being redesignated to attainment and maintenance status. With the submittal of this Maintenance Plan, Provo meets all these criteria. Table 6 identifies the prerequisites for a Redesignation Request. Table 7 identifies the prerequisites for a Maintenance Plan.

Table 6. Prerequisites to Redesignation

Category	Requirement	Reference	Addressed in Section
Attainment of Standard	The State must provide two complete, consecutive calendar years of quality-assured monitoring data in accordance with 40 CFR 58.	CAA: Sec. 107(d)(3)(E)(i)	IX.C.6.e(1)
Section 110 and Part D Requirements	The state must verify that the area has met all requirements applicable to the area under Section 110 and Part D.	Sec. 107(d)(3)(E)(v); Sec. 110(a)(2); and Sec. 171 of CAA	Completeness Memo in Administrative Documentation
Oxygenated Gasoline Program	In a CO nonattainment area that is redesignated as attainment for CO, the requirements of this subsection shall remain in effect to the extent such program is necessary to maintain the standard thereafter in the area.	CAA: Sec. 211(m)(6)	IX.C.6.e(4)
State Implementation Plan Approval	The state must verify that a fully approved SIP is in place for the area under section 110(k) of CAA.	Sec. 107(d)(3)(E)(ii) and Sec. 110(k) of CAA	IX.C.6.c(4)
Permanent and Enforceable Emissions Reductions	The state must verify that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from enforcement of the SIP, federal regulations, and other permanent and enforceable regulations.	Sec. 107(d)(3)(E)(iii) of CAA	IX.C.6(d)(2)
Maintenance Plan	To be redesignated to attainment, the State must have a fully approved maintenance plan in place.	Sec. 107(d)(3)(E)(iv)	

Table 7. Requirements of a Maintenance Plan

Category	Requirement	Reference	Section
Maintenance Demonstration	Provide for maintenance of the relevant NAAQS in the area for at least 10 years after redesignation. Demonstration is made by modeling to show that the future mix of sources and emission rates will not cause a violation of the NAAQS.	Sec. 175A(a) of CAA and Calcagni memo, Sept. 4, 1992	IX.C.6.e(3)
Verification of Continued Maintenance	The maintenance plan must indicate how the State will track the progress of the maintenance plan.	Calcagni memo, Sept 4, 1992	IX.C.6.e(6)
Revise in 8 years	The State must commit to revising the maintenance plan 8 years after redesignation.	Sec. 175A(b) of CAA	IX.C.6.e(6)(d)
Contingency Measures	Areas seeking redesignation from nonattainment to attainment are required to develop contingency measures that include State commitments to implement additional control measures in response to future violations of the NAAQS.	Sec. 175A(d) of CAA, Calcagni memo, Sept. 4, 1992	IX.C.6.e(5)

(a) Existing Controls

The controls necessary to attain the NAAQS are outlined in Section c.4 (Control Strategies) of the Attainment Plan in this revision of the SIP, and include a requirement for the sale of 2.7% oxygenated fuel in Utah County, and vehicle Inspection/Maintenance (I/M) program, and controls on wood-burning devices during no-burn periods in Utah County.

(b) Monitoring Network / Data Analysis

The monitoring network is discussed in Section b (Monitoring Network) of this revision of the SIP.

(2) Improvement in Air Quality Due to Permanent & Enforceable Emission Reductions

Under the provisions of the Clean Air Act section 107(d)(3)(E)(iii), the State must verify that the improvement in air quality is due to permanent and enforceable reductions in emissions. Emission data must be examined for evidence of temporary reduction in emission rates (e.g. reduced production or shutdown due to temporary adverse economic conditions) or unusually favorable meteorology that may have contributed to attainment, and, if appropriate, the State must assure that recovery from the above conditions will not jeopardize continued maintenance of the standard.

(a) Permanent and Enforceable Emission Reductions

Reductions in carbon monoxide emissions in the Provo nonattainment area have primarily resulted from implementation of the following programs:

- the Federal Motor Vehicle Emission Control Program
- Utah County's Vehicle Emissions Inspection and Maintenance Program

Because these controls have been federally approved, the resulting CO emission reductions are federally enforceable and permanent. This plan incorporates Utah's commitment to continue to enforce all applicable requirements of the State Implementation Plan, except for changes identified in Subpart e(4)(a) below, after Provo is redesignated to attainment. The emission benefits from these controls (as modified in Subpart 3(4)(b)) have been accounted for in the CO emission inventory projections for the maintenance provisions of this plan.

Continued reductions in carbon monoxide emissions through the year 2015 are anticipated as a result of the Tier II federal vehicle emission standards promulgated on February 10, 2000 (65 FR 6698). In addition, Utah County Health Department will continue to operate its vehicle inspection program.

(b) Meteorology and Ambient Conditions

For redesignation of the Provo nonattainment area to attainment, it is important to show that reductions in ambient carbon monoxide concentrations are due to permanently enforceable emission reductions, and not to reductions resulting from year-to-year meteorological variations.

The air pollution potential for Provo continues to exist due to the ongoing presence of stagnation periods (inversions) prevalent in the area. For reference, the most recent violation year was 1993, and 1994 - 2002 were non-violation years for CO in Utah County.

Historically, elevated CO values in Utah County have been associated with inversion episodes during the autumn and winter. Inversions are characterized by strong positive temperature gradients with height, low wind speeds, and minimal atmospheric mixing. The inversions are strongest and most persistent in the autumn and winter months when solar heating is at a minimum. Minimum CO levels were recorded during the time of maximum solar heating.

A Clearing Index (CI) has been developed to quantitatively assess the intensity of inversion periods. The CI is a numerical, non-dimensional value ranging from less than 50 in the worst stagnant conditions to more than 1000 during the least stagnant conditions. A value of 250 or less indicates inversion conditions. The CI is based on two variables: 1) the vertical diffusion of pollutants (the mixing depth), and 2) the wind speed in this mixing depth that results in horizontal transport of pollutants. The CI is calculated as follows:

CI = Surface Wind (knots) X Mixing Height (feet) / 100

Radiosonde data of the vertical structure of winds, temperature, and humidity are the primary source of specific data used in determining CIs for Utah County. Radiosondes are released twice daily by the National Weather Service (NWS) located at the north end of Geneva Steel plant property in Utah County.

As shown in Table 8 below, violations of the eight-hour NAAQS for carbon monoxide occur during high or moderate stagnation periods with very low CIs (150 or less). The values contained in this table were taken from NWS data collected at the Geneva Steel plant property and UDAQ monitoring records.

Table 8. Monitored Carbon Monoxide Violations (8-hour avg.) and Clearing Indices for Utah County, 1993

Monitor Site	Date	Hour	Monitored Conc. (ppm)	CI	Wind Sp. (mph)
North Provo	12/14/93	2300-2400	10	150	2.7
North Provo	11/29/93	2300-2400	10	150	2.7

Three exceedances of the standard occurred between 1994 and 1996. These exceedances were reviewed (see Table 9) for similarity with the violations that occurred during 1993 (see Table 8).

Table 9. Monitored Carbon Monoxide Exceedances (8-hour avg.) and Clearing Indices (CIs) for Utah County, 1994-1996.

Monitor Site	Date	Hour	Monitored Conc. (ppm)	CI	Wind Sp. (mph)
University #2	1/22/94	0000-0100	10	80	2.3
University #2	2/9/96	0000-0100	10	25	2.3
University #3	2/9/96	0000-0100	10	25	2.3

Table 10 indicates the number of days with a Clearing Index (CI) equal to or below 250 for the period from 1990 through 2002. A yearly breakdown of this table appears in the Technical Support Documentation (Section 5, CD-ROM).

Table 10. Total Inversion Days (Clearing Index<250)

Year	0-100 CI	101-250 CI	0-250 CI
1990	19	36	55
1991	49	43	92
1992	39	42	81
1993	35	53	88
1994	17	29	46
1995	20	40	60
1996	24	29	53
1997	24	46	70
1998	30	36	66
1999	55	44	99
2000	53	45	98
2001	48	44	92
2002	55	43	98

Meteorology for Utah County over the past 10 years confirms this area continues to experience wintertime inversion periods. These periods are equal in severity and frequency to that which occurred during the early 1990s time period. However, no violations of the CO standard have occurred since 1993. This demonstrates that meteorological variables did not significantly influence the reduction in ambient CO concentrations in Provo. This position is further substantiated by information and analyses contained in the Episode Selection Documentation in Volume 12, Section 4.b.ii of the Technical Support Document.

(c) Emissions Have Not Been Influenced by Temporary Economic Conditions

The State is required to demonstrate that point source carbon monoxide emissions for Provo have not been reduced due to temporary economic conditions. The only significant point sources for carbon monoxide that could impact the Provo nonattainment area were the Geneva Steel sinter plant and the cupola at Pacific States Cast Iron Pipe Company (Pacific States). During the development of the 1994 SIP, these sources were both modeled and demonstrated to have insignificant impact on the NAAQS.

Other demographic factors clearly are not responsible for the improvement in ambient carbon monoxide levels in Provo. Over the last ten years, the area has experienced strong growth in vehicle miles traveled, as displayed in Table 11, while concurrently achieving a significant reduction in monitored carbon monoxide levels.

Table 11. Vehicle Miles Traveled in Provo and Utah County, 1990-2001

Annual Average Daily Traffic (AADT) **Vehicle Miles Traveled** (VMT)		
Year	Provo	Utah County
1993	1,220,412	5,656,533
1994	1,286,466	6,012,331
1995	1,316,015	6,356,477
1996	1,342,453	6,733,700
1997	1,488,093	7,216,446
1998	1,536,750	7,537,532
1999	1,615,785	8,008,574
2000	1,629,763	8,272,574
2001	1,629,978	8,628,699

Source: Utah Department of Transportation (UDOT)

e. MAINTENANCE DEMONSTRATION

(1) Base Year Emissions Inventories

The annual emissions inventory identifies CO emissions from different sources in Utah County. Maximum CO concentrations occur during winter temperature inversions; therefore the inventories used in this attainment demonstration reflect emissions on an average winter day. Mobile sources generate approximately 93 percent of the carbon monoxide (CO) emitted in Utah County. Figure 4 illustrates the distribution of daily CO emissions in Provo for the base-year episode in 2000, and Figure 5 illustrates the distribution of daily CO emissions in Provo for the base-year episode in 2001.

Figure 4. Provo 2000 Base-Year Inventory

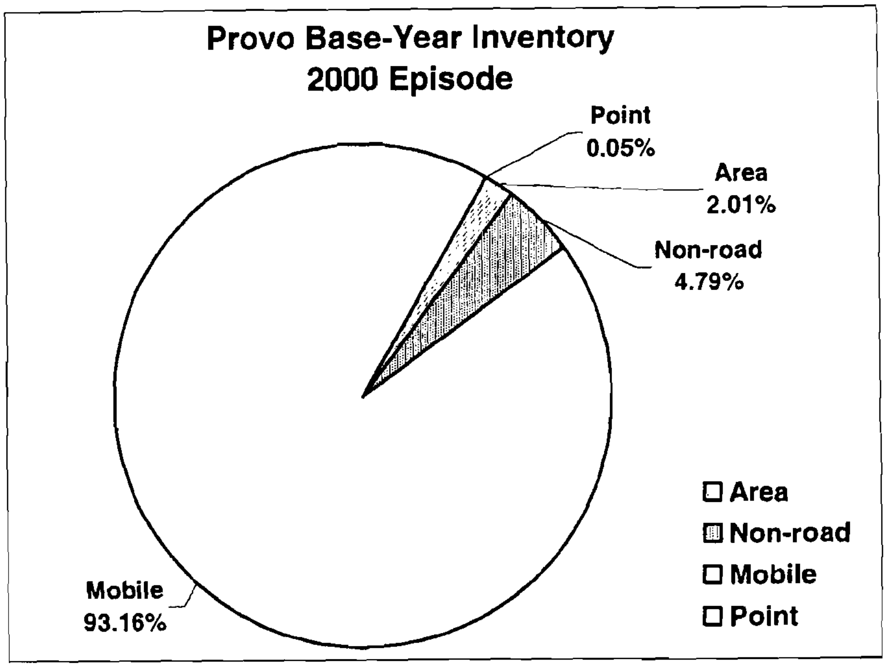
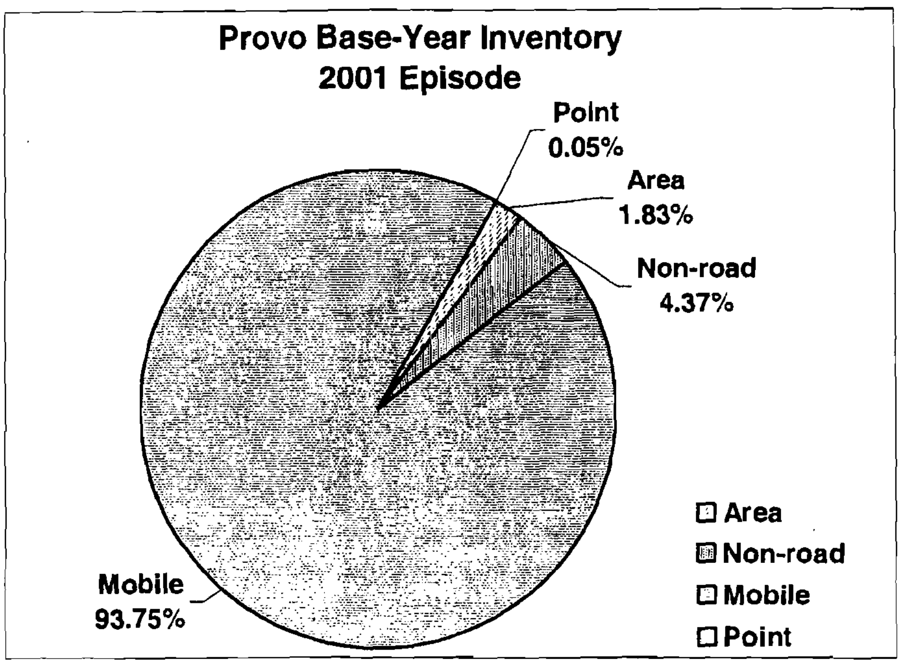


Figure 5. Provo 2001 Base-Year Inventory



The base-year episodic emissions inventories are divided into four major sections: point sources, area sources, non-road sources, and mobile sources. A discussion of each of these three sections follows. Table 12 below shows peak CO daily emissions from each category in tons/day for Provo for each base-year episode.

Table 12. 2000 and 2001 Provo Base-Year Inventories

Provo (Tons per Day)

	2000	2001
Mobile	59.44	65.38
Point	0.03	0.03
Area	1.28	1.28
Non-Road	3.05	3.05
Total	63.80	69.74

(a) Point Sources

Since Provo is a moderate CO non-attainment area, hotspot modeling for point sources using ISCST3 is not required. Emissions from point sources were input to the UAM-AERO model, and the mobile modeling results from CAL3QHCR were paired in time and space with the output from UAM-AERO.

(b) Area Sources

The area source inventory for Provo was derived from the UAM-AERO model using a grid-based allocation of emissions within the Provo municipal boundaries.

(c) Mobile Sources

Mountainland Association of Governments (MAG) provided the mobile source inventory using the current MOBILE emission model and applicable transportation data. The analysis is found in Volume 10, Section 3.b.i, Provo/Utah County On-Road Mobile Sources, TSD.

(2) Modeling Demonstration

(a) Episode Selection

The technical analysis of CO concentrations in the Provo/Orem area completed in 1994 concluded that the CO problem was probably occurring primarily at one particular intersection on University Avenue in Provo. The application of source specific modeling of two large industrial sources, Geneva Steel and Pacific States Cast Iron Pipe, indicated that the elevated CO concentrations at specific intersections were not influenced by emissions from these sources. In addition, detailed meteorological analysis of both the observation record and prognostic modeling showed that very specific meteorological conditions accompanied elevated CO concentrations. An analysis of the CO monitoring database for the Provo/Orem area, combined with the meteorological record over the last decade, indicates that the conclusions reached in the previous analysis--i.e., that the CO problem occurs primarily at a single intersection in Provo, and that elevated concentrations at specific intersections are not influenced by emissions from point sources-- continue to be valid today. Section 2 of the Episode Selection Document describes in detail the analysis used to select the base year modeling episodes. Detailed discussion of episode selection is found in the Episode Selection Document in Volume 12, Section 4.b.i of the TSD.

(b) Episode Modeling

The CO Modeling Protocol (UAM-CAL3QHCR Modeling Results, Volume 12, Section 4.a of the TSD) describes in detail the suite of models used for this analysis. A combination of the CAL3QHCR traffic model and the UAM-AERO regional model were used to capture the effects of the local contribution to CO from automobiles at intersections and the more generalized contribution to background CO. The results of these two models are summed to derive an estimate of the total CO concentration that can be expected at "hot spot" intersections where CO is expected to be the highest.

The episodes were modeled with the control strategies in place at the time, including use of oxygenated gasoline in Utah County. In addition, the model was run for the projection years with future control measures discussed in Subpart (4) below, i.e., eliminating oxygenated fuel and incorporating the recently revised Utah statute 41-6-163.6 providing for biennial I/M vehicle emissions testing for vehicles six years old and newer. Table 13 displays the inventory used in the modeling.

Table 13. Carbon Monoxide Emission Inventories for the Provo Modeling Domain

Provo (Tons per Day)

Source	2005	2006	2008	2011	2014	2015
Mobile	70.44	72.10	59.69	55.75	52.88	52.46
Point	0.04	0.04	0.04	0.04	0.05	0.05
Area	1.18	1.17	1.10	1.03	0.97	0.96
Non-Road	3.05	3.03	2.97	2.90	2.86	2.87
Total	74.71	76.34	63.80	59.72	56.76	56.34

Only one intersection, 500 N. University Avenue and Center Street, shows an exceedance of the standard in 2001 (Table 14). The highest monitored value in Provo in 2001 was 7.5 ppm (See Table 2), at a monitor that is only 3 blocks from the modeled intersection. Given that the monitored data for 2001 indicates no exceedances, and that projected values for all future years are lower than the standard, the modeled exceedance in 2001 is an indication that the model is conservative in its projections. Further information about the episódic modeling strategy and results is available in the modeling documentation contained in Volume 12, Section 4.b.ii of the Technical Support Document. Results are displayed in Tables 14 and 15 and are shown graphically in Figures 6 and 7.

TABLE 14. 2000 EPISODE AND PROJECTIONS: 8-HOUR MAXIMUM CO CONCENTRATIONS (PPM)

Location	2000	2004	2005	2006	2007	2008	2011	2014	2015
University Ave University Parkway	8.3	7.9	7.9	8.1	6.5	6.5	6.0	5.6	5.5
1230 North University Ave	7.1	6.6	6.6	6.8	5.5	5.5	5.0	4.7	4.6
1230 North 500 West	7.7	7.2	7.2	7.3	5.9	5.9	5.4	5.0	4.9
500 West Center St.	8.5	8.0	8.0	8.2	6.5	6.5	6.1	5.6	5.6
500 North University Ave & Center St.	8.6	8.4	8.3	8.5	6.9	6.9	6.3	5.9	5.8

Figure 6. 2000 Episode CAL3QHCR + UAM AERO

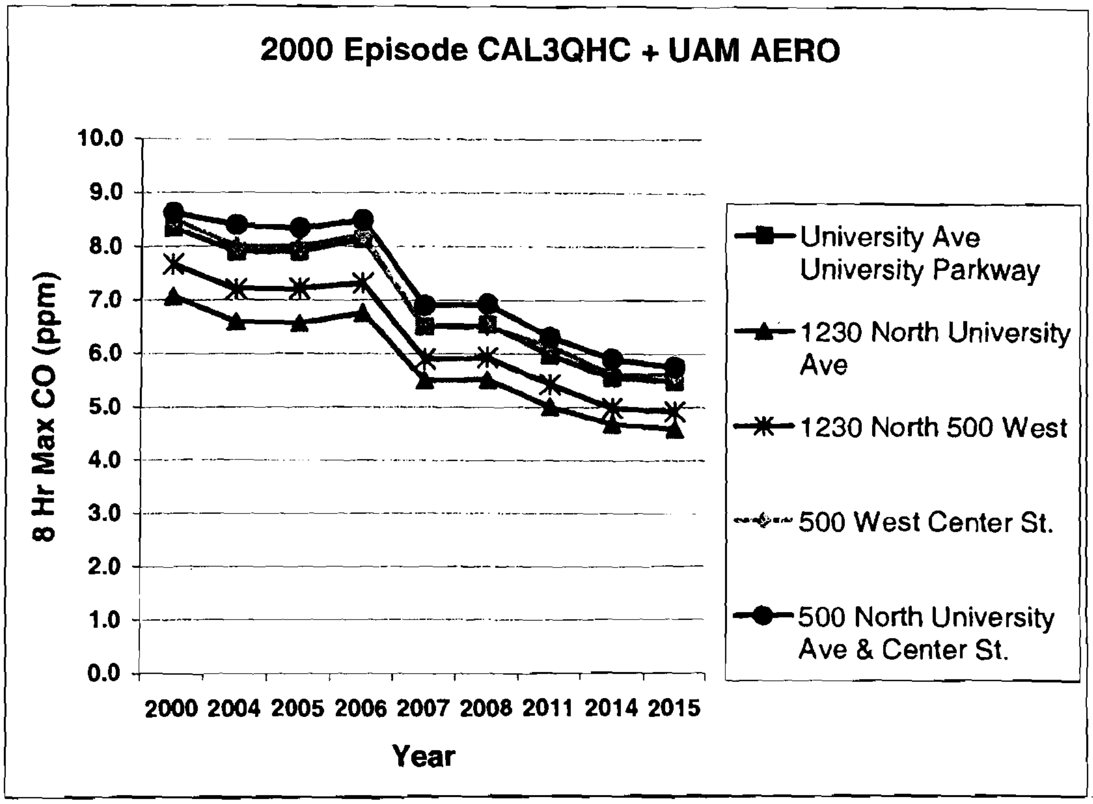
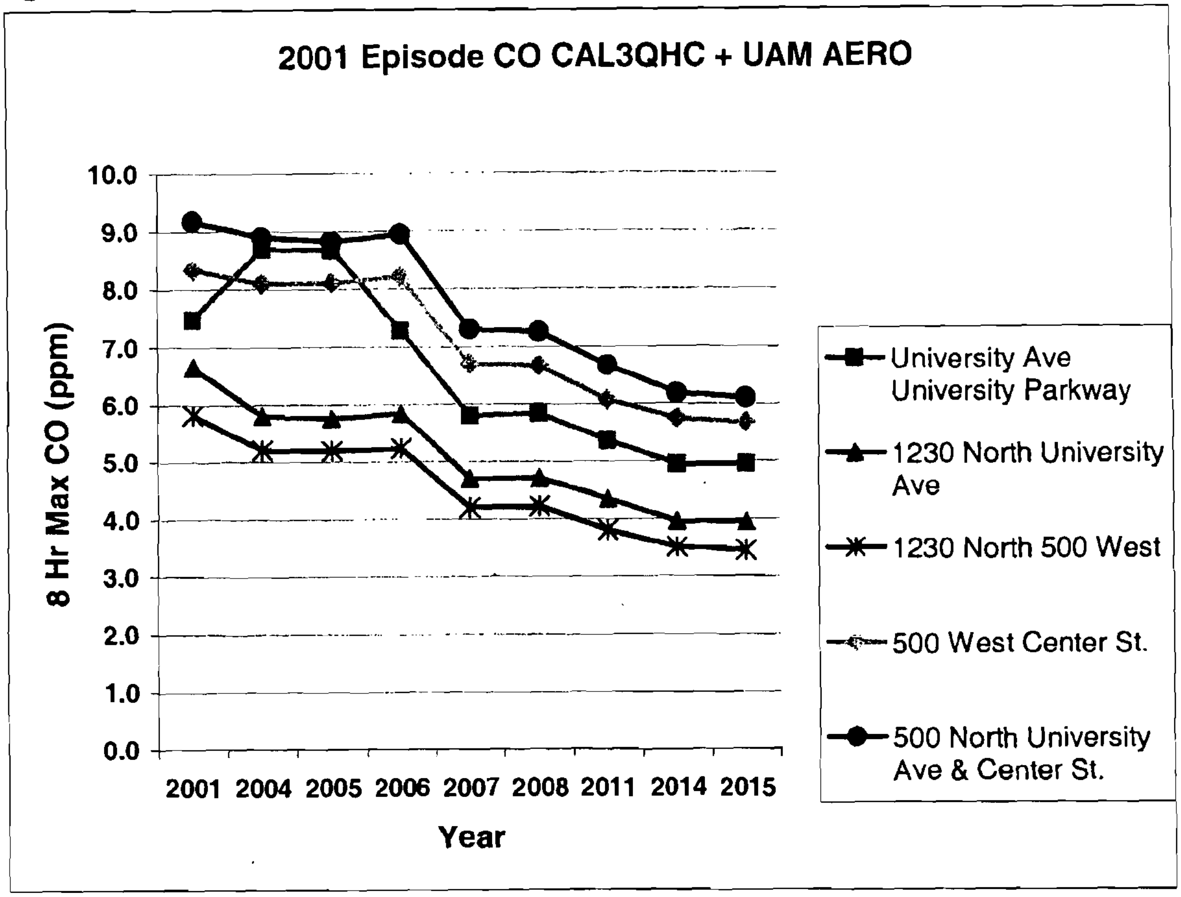


TABLE 15. 2001 EPISODE AND PROJECTIONS: 8-HOUR MAXIMUM CO CONCENTRATIONS (PPM)									
Location	2001	2004	2005	2006	2007	2008	2011	2014	2015
University Ave University Parkway	7.5	8.7	8.7	7.3	5.8	5.8	5.4	4.9	4.9
1230 North University Ave	6.7	5.8	5.8	5.8	4.7	4.7	4.3	4.0	3.9
1230 North 500 West	5.8	5.2	5.2	5.2	4.2	4.2	3.8	3.5	3.4
500 West Center St.	8.3	8.2	8.1	8.2	6.7	6.7	6.1	5.7	5.7
500 North University Ave & Center St.	9.2	8.9	8.8	8.9	7.3	7.3	6.7	6.2	6.1

Figure 7. 2001 Episode CAL3QHCR + UAM AERO



(3) **Revisions in Existing Control Measures**

(a) Oxygenated Gasoline

As a result of cleaner cars in the fleet, emission projections in Tables 15 and 16 show that it is possible to revise the current carbon monoxide control program as early as November 2004 while continuing to maintain compliance with the carbon monoxide standard through 2015.

The modeling analysis conducted for this maintenance plan included modifications to the area's control measures, i.e., elimination of oxygenated gasoline and revising Utah County's vehicle emission I/M program.

The analysis completed for this Maintenance Plan also indicates that at this time it is not possible to eliminate routine vehicle maintenance testing in Utah County while ensuring compliance with the National Ambient Air Quality Standard for carbon monoxide. Realizing the benefits of OBD technology, low failure rates, significantly lower emissions and increased durability of newer vehicles, however, it is possible to reduce test frequency for vehicle model years six years and newer from an annual inspection to a biennial (every two years) inspection cycle.

Provo will rely on the control programs listed below to demonstrate maintenance of the carbon monoxide standards through 2015. No emission reduction credit has been taken in the maintenance demonstration for any other current state or local control programs and no other such programs, strategies or regulations shall be incorporated or deemed enforceable measures for the purposes of this maintenance demonstration.

Specific programs and requirements that will cease to be part of the State Implementation Plan are:

- Oxygenated Gasoline

- Annual I/M testing of vehicle model years six years or newer will be replaced with biennial testing of those vehicles. Older vehicles will continue to be tested annually.

(b) Enforceable Control Measures

The following control measures will remain in force after redesignation to attainment.

- Federal tailpipe standards and regulations, including those for small engines and non-road mobile sources. Credit is taken for these federal requirements, but they are not part of the Provo plan;

- Utah County Vehicle Emissions Inspection and Maintenance Program. Program requirements are documented in SIP Section X, Parts A and D;

- Winter Wood Burning Control Program (R307-302-3);

- Utah State Implementation Plan, Section IX, Control Strategies for Area and Point Sources, Part C, Carbon Monoxide, Salt Lake City, Ogden City and Utah County, last amended in 2004;

- Prevention of Significant Deterioration regulations (R307-405) will apply in Provo.

(4) Contingency Plan

Section 175A(d) of the Act requires that maintenance plans assure prompt action to correct any violation of the standard that occurs after the area is redesignated to attainment. Additional controls are to be implemented to achieve sufficient CO emission reductions to eliminate any future CO violations. The triggering of contingency measures does not automatically require a revision to the SIP or redesignation to nonattainment.

(a) Determination of Contingency Action Level

Within 30 days after any monitored exceedance of the carbon monoxide standard, DAQ will complete validation and quality-assurance of the data. The contingency action level will be triggered on the date that either of the following conditions is met:

- the second, non-overlapping 8-hour average ambient CO measurement exceeds 9 parts per million (ppm) at a single monitoring site during one calendar year; or

- the second one-hour average ambient CO measurement exceeds 35 ppm at a single monitoring site during one calendar year.

(b) If the Action Level Is Exceeded

Under the State-EPA Performance Partnership Agreement, the Utah Air Monitoring Center notifies EPA within days of any exceedance of any standard. This is raw data, and Utah will not trigger implementation of contingency measures until quality-assured monitoring data indicates it is necessary. Under 40 CFR 58.35, the State is required to submit to EPA the quality-assured monitoring data within 90 days after the end of each calendar quarter.

If the contingency action level, as validated by appropriate quality-assurance procedures, is exceeded, the Executive Secretary will take the following actions within 30 days following the trigger date in (a) above:

- begin steps to implement the CO Contingency Measures that are included in Subpart (c) below; and

- prepare a report that outlines the recorded ambient measurements of the CO standard, the causes of the violation, and the actions that have been taken to implement contingency measures, including a schedule of future actions needed to implement contingency measures. This report will be submitted to the Air Quality Board within 45 days following the trigger date in (5)(a) above, and to EPA within 15 days after it is sent to the Board.

The Board will hold a public meeting to consider the recommended contingency measures, along with any other contingency measures the Board believes may be appropriate to effectively address the causes of the violation. The Board will adopt and implement the necessary contingency measures before the November 1 beginning of the next winter season.

Implementation of the oxygenated gasoline program will require a rule-making action by the Air Quality Board, as well as some lead time for the refiners to order and receive the oxygenate. Implementation of annual vehicle inspections for all vehicles also will require Board action to adopt a SIP revision, and inspection stations will need to expand their capacity to accommodate the increased inspection load. Exactly how much lead time will be needed will be part of the Executive Secretary's investigations and recommendations to the Board.

(c) Contingency Measures

The State will implement contingency measures under this Plan if the contingency action level in Subpart e(5)(a) is exceeded. As required by Section 175A of the Act, the contingency measures to be implemented are:

- implementation of 2.7% oxygenated gasoline in Utah County from November 1 through the end of February, beginning within one year after it has been determined that the action level has been exceeded: and

- a return to annual vehicle emissions inspections.

(5) Verification of Continued Attainment

(a) Tracking System for Verification of Emission Inventory

Continued maintenance of the CO standard in the Provo maintenance area depends in large measure upon the ability of the state to track CO emissions in future years. As demonstrated in Subpart e(1) above, mobile source emissions are the largest source of CO emissions in Provo. By July 1 of 2006, 2007, 2009, 2012, 2015, and 2016, the State will use available inventory data to verify that the emissions inventory contained in Table 14 of this plan is not exceeded.

(b) Analyze Ambient CO Monitoring Data

The State will analyze the ambient CO monitoring data with respect to the level of the CO standard and log the data into AIRS. Any exceedance of the standard will be reported to EPA within 30 days, and quality-assured data will be reported as required under 40 CFR Part 58.

(c) Annual Review of the CO Monitoring Network

The State will continue to evaluate the ambient CO monitoring network to ensure that the network meets all applicable federal regulations and guidelines. The results of this evaluation will be submitted to EPA by June 1st of each year in the annual Network Review.

(d) Provisions for Revising the Maintenance Plan

The State will revise this Plan as necessary in response to revisions of the national primary ambient CO standard. The State will also revise the Plan as necessary to comply with any EPA finding that the Plan is inadequate to attain or maintain the national ambient standard, and eight years after redesignation to attainment, in compliance with Section 175A of the Act.

(e) Provisions for Prohibiting Emissions That Interfere With Attainment In Other States

The State will take steps as necessary to prohibit emissions within the state that have been shown to interfere with attainment or maintenance of a NAAQS in another state.

(f) Subsequent Maintenance Plan Revisions

The Clean Air Act requires that a maintenance plan revision be submitted to the EPA no later than eight years after promulgation of the original redesignation. The purpose of this revision is to provide for maintenance of the NAAQS for an additional ten years following the first ten-year period. The State of Utah commits to submit a revised maintenance plan eight years after redesignation to attainment, as required by the Act.

f. CONFORMITY

The transportation conformity provisions of section 176(c)(2)(A) of the CAA require regional transportation plans and programs to show that "...emissions expected from implementation of plans and programs are consistent with estimates of emissions from motor vehicles and necessary emissions reductions contained in the applicable implementation plan..."

EPA=s transportation conformity regulation (40 CFR 93.118, August 15, 1997) also requires that motor vehicle emission budgets must be established for the last year of the maintenance plan, and may be established for any years deemed appropriate. If the maintenance plan does not establish motor vehicle emissions budgets for any years other than the last year of the maintenance plan, the conformity regulation requires a Ademonstration of consistency with the motor vehicle emissions budgets must be accompanied by a qualitative finding that there are not factors which would cause or contribute to a new violation or exacerbate an existing violation in the years before the last year of the maintenance plan.≅ The normal interagency consultation process required by the regulation shall determine what must be considered in order to make such a finding.

For transportation plan analysis years after the last year of the maintenance plan (in this case 2015), a conformity determination must show that emissions are less than or equal to the maintenance plan=s motor vehicle emissions budget(s) for the last year of the implementation plan. EPA=s conformity regulation (40 CFR 93.124) also allows the implementation plan to quantify explicitly the amount by which motor vehicle emissions could be higher while still demonstrating compliance with the maintenance requirement. The implementation plan can then allocate some or all of this additional Asafety margin≅ to the emissions budgets for transportation conformity purposes.

Provo Mobile Source CO Emissions Budgets, in Tons/Day (tpd), for 2014 and 2015 and Beyond:

With this maintenance plan, the State is establishing transportation conformity motor vehicle emission budgets (MVEB) for 2014 and for 2015 and beyond as follows.

CO Emissions Budget for 2014

As presented in Table 13, emissions from point sources of 0.05 tpd, emissions from area sources of 0.97 tpd, emissions from non-road emissions of 2.86 tpd, and emissions from mobile sources of 52.88 tpd were modeled with UAM-AERO and CAL3QHC. These values predicted maintenance of the CO standard at the evaluated intersections as presented in Tables 14 and 15. For transportation conformity purposes, the State is using the same point, area, and non-road tons per day emission figures for 2014 and increasing the mobile source emissions to 70.44 tpd. These higher mobile source emission figures were then re-modeled and also showed predicted maintenance of the CO standard at the evaluated intersections. These results are presented in Tables 16 and 17. By modeling mobile source emissions at 70.44 tpd, this effectively produced a Asafety margin≅ of 17.56 tpd. This maintenance plan estimates the available Asafety margin≅at 17.56 tpd and allocates all this Asafety margin≅ to the transportation MVEB for 2014 for a total of 70.44 tpd.

CO Emissions Budget for 2015 and Beyond

As presented in Table 13, emissions from point sources of 0.05 tpd, emissions from area sources of 0.96 tpd, emissions from non-road emissions of 2.87 tpd, and emissions from mobile sources of 52.46 tpd were modeled with UAM-AERO and CAL3QHC. These values predicted maintenance of the CO standard at the evaluated intersections as presented in Tables 14 and 15. For transportation conformity purposes, the State is using the same point, area, and non-road tons per day emission figures for 2015 and increasing the mobile source emissions to 72.10 tpd. These higher mobile source emission figures were then re-modeled and also predicted maintenance of the CO standard at the evaluated intersections. These results are presented in Tables 16 and 17. By modeling mobile source emissions at 72.10 tpd, this effectively produced a Asafety margin≅ of 19.64 tpd. This maintenance plan estimates the available Asafety margin≅at 19.64 tpd and allocates all this Asafety margin≅ to the transportation MVEB for 2015 and beyond for a total of 72.10 tpd.

The MVEB of 70.44 tpd for 2014 and 72.10 tpd for 2015 and beyond will be used to determine whether plans, programs, and projects comply with the SIP in applicable horizon years. These new MVEB will take effect for future transportation conformity determinations upon approval of this Maintenance Plan or upon a finding of adequacy by EPA, whichever comes first.

TABLE 16. 2000 EPISODE CONFORMITY BUDGET PROJECTIONS: 8-HOUR MAXIMUM CO CONCENTRATIONS (PPM)

Location	2014	2015 and Beyond
University Ave University Parkway	6.3	6.3
1230 North University Ave	5.4	5.4
1230 North 500 West	5.7	5.8
500 West Center St.	6.3	6.3
500 North University Ave & Center St.	6.6	6.5

TABLE 17. 2001 EPISODE CONFORMITY BUDGET PROJECTIONS: 8-HOUR MAXIMUM CO CONCENTRATIONS (PPM)

Location	2014	2015 and Beyond
University Ave University Parkway	5.2	5.3
1230 North University Ave	4.4	4.4
1230 North 500 West	3.8	3.8
500 West Center St.	5.9	5.9
500 North University Ave & Center St.	6.6	6.6

Carbon Monoxide Maintenance Provisions for Salt Lake City

Section IX, Part C.7

Adopted by the Air Quality Board
October 6, 2004

Table of Contents

List of Tables and Figures

IX.C.7.a Background

The Environmental Protection Agency (EPA) approved a redesignation request and maintenance plan for Salt Lake City on January 21, 1999 (64 FR 3216), effective March 22, 1999. The action, which was adopted by the Utah Air Quality Board on September 4, 1996, established an attainment year of 1993, demonstrated maintenance through 2006, provided for the continuation of the Salt Lake County inspection and maintenance program, established a carbon monoxide mobile source emissions budget for a number of years for mobile sources (to be used in transportation conformity determinations), and established a contingency plan in the event a violation of the carbon monoxide standards or an exceedance of the 1993 planning cap was measured.

This revised maintenance plan provides for the continuation of the County's inspection and maintenance program as defined in Salt Lake City-County Health Department Ordinance #22A, revises the emission inventories and maintenance demonstration, revises the 2005 on-road mobile source carbon monoxide attainment emissions inventory for 1993, adds a mobile source emissions budget for 2019, and revises the contingency plan.

IX.C.7.b Emission Inventories and Maintenance Demonstration

The emission inventories for the 1993 attainment year and the 2019 maintenance year are presented below in Tables 1 and 2. Each inventory accounts for the emission control programs effective during that period, and the following controls will continue to be implemented to ensure maintenance of the carbon monoxide standards through the year 2019.

- Federal Motor Vehicle Control Program.
- Stationary Sources. The Salt Lake City attainment/maintenance area is subject to the Prevention of Significant Deterioration permitting requirements of R307-405, the requirements of R307-401 and R307-403. R307-401:405 are already included in the State Implementation Plan. The maintenance plan makes no changes to these regulations.
- Improved Automobile Inspection and Maintenance Program. Salt Lake City-County Health Department Ordinance #22A. The program is set forth in SIP Section X.C, the Salt Lake County Vehicle I/M program, last approved by EPA on October 9, 2002, at 67 FR 62891.

Both inventories represent emissions on a typical winter weekday during the peak carbon monoxide season. (November through January for the respective year). These inventories use EPA-approved emissions modeling methods and the latest transportation data from the Wasatch Front Regional Council's (WFRC) 2004 - 2030 transportation plan found by the Federal Highways Administration on January 20, 2004, to conform to the state implementation plan. Demographic data was obtained from the Governor's Office of Planning and Budget. The inventories were developed by the Division of Air Quality (DAQ) in coordination with WFRC. Detailed information on model assumptions and parameters for each source category are found in the Technical Support Document at Tab 2.

The 1993 inventory included in the original 1996 Maintenance Plan indicated total winter weekday emissions of 225.73 tons, with 202.24 tons coming from on-road mobile sources. Table 1 below differs from that inventory because methodologies for collecting and estimating inventory data have changed since 1996. Therefore, the 1993 inventory has been re-calculated using current methods so that it can be compared with the projections for future years. Methodology changes are explained in the Technical Support Document at Tab 2. The principal factor is the difference between mobile source emission projections using the currently-approved MOBILE6.2 version of the model, compared to the now outdated MOBILE 5 version used in the 1996 submittal.

The newly-calculated 1993 inventory in Table 1 below indicates that total winter weekday emissions were 345.39 tons, with 295.21 tons coming from on-road mobile sources. Though the inventory appears to be considerably higher than the original inventory, it reflects the differences in the new MOBILE6.2 model; no additional emissions are included, and the monitoring data in IX.C.7.c below indicates that ambient concentrations of carbon monoxide have declined since 1993. This Plan constitutes a maintenance demonstration for carbon monoxide in Salt Lake City through 2019.

Tables 1 and 2 show the comparable inventories for 1993 and 2019. Figure 1 shows the proportion of carbon monoxide coming from each kind of source.

Table 1. **1993 Attainment Year Carbon Monoxide Emission Inventory for the Salt Lake City Attainment/Maintenance Area.**

		CO Emissions Tons/Winter Week Day
Area Sources		
Agricultural Burning		n/d
Aircraft Maintenance		0.013
Coal Combustion-commercial		0.456
Coal Combustion-industrial		1.150
Coal Combustion-residential		0.024
Detonation		n/d
Firefighter Training		n/d
Forest Fires		n/d
Natural Gas Combustion-comm & Indus		1.485
Natural Gas Combustion-residential		0.879
Oil Combustion-commercial		0.042
Oil Combustion-residential		0.004
Open Burning		n/d
Orchard Heaters		n/d
Structural Fires		0.037
Vehicle Fires		0.009
Wood Combustion		11.245
	Total Area Sources	**15.344**
Mobile Sources		
On-Road	*Total On-road Sources*	**295.210**
Non-Road		
Aircraft		1.266
Railroad		0.184
Misc. Non--road Equipment		33.39
	Total Non-road Sources	**34.84**
Point Sources	*Total Point Sources*	0*
	TOTAL 1993 Inventory	**345.39**

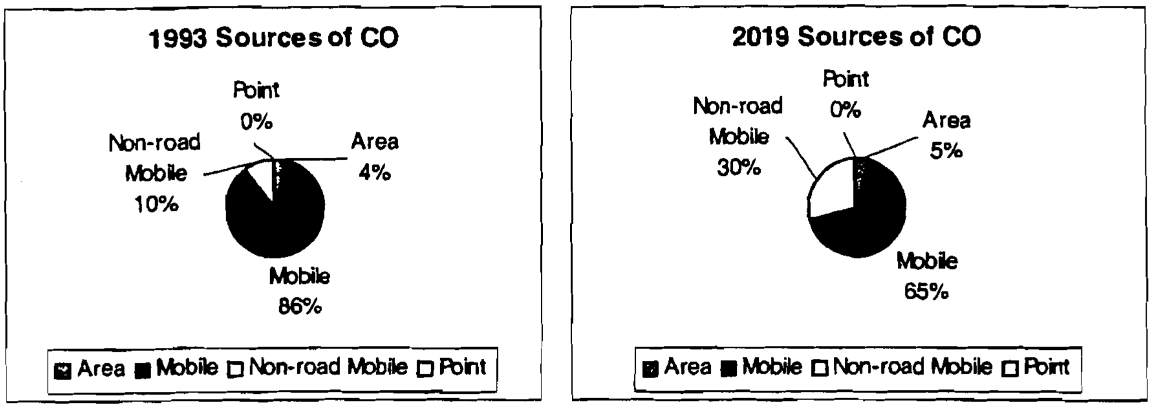
Note: Numbers may vary slightly from report due to rounding
Numbers may not add due to rounding
n/d = negative declaration
*There were no major CO point sources in the maintenance area in 1993; point source emissions are included in the Area Source inventory.

Table 2. 2019 Attainment Year Carbon Monoxide Emission Inventory for the Salt Lake City Attainment/Maintenance Area.

		CO Emissions Tons/Winter Week Day
Area Sources		
Agricultural Burning		n/d
Aircraft Maintenance		0.02
Coal Combustion-commercial		0.74
Coal Combustion-industrial		0.99
Coal Combustion-residential		0.04
Detonation		n/d
Firefighter Training		n/d
Forest Fires		n/d
Natural Gas Combustion-commercial		0.88
Natural Gas Combustion-industrial		n/d
Natural Gas Combustion-residential		0.82
Oil Combustion-commercial		0.01
Oil Combustion-residential		0.00
Open Burning		n/d
Orchard Heaters		n/d
Structural Fires		0.06
Vehicle Fires		0.01
Wood Combustion		3.77
	Total Area Sources	*7.34*
Mobile Sources	*Total On-road Sources*	*104.08*
On-Road		
Non-Road		
Aircraft		1.91
Railroad		0.22
Misc. Non-road Equipment		46.24
	Total Non-road Mobile	*48.37*
Point Sources	*Total Point Sources*	*0**
	Total Salt Lake Emissions	**159.79**

Note: Numbers may vary slightly from report due to rounding
Numbers may not add due to rounding
n/d = negative declaration
*There were no major CO point sources in the maintenance area in 1993; point source emissions are included in the Area Source inventory.

Figure 1. 1993 and 2019 CO Emission Sources in Salt Lake City



DAQ also performed an analysis that shows the projected levels of emissions for the years 2004, 2005, 2008, 2011, 2014 and 2017 are below the 1993 attainment inventory as shown in Table 3. The details are found in the Technical Support Document at Tab 2. These years were selected to demonstrate that Salt Lake City will not experience an unexpected increase in emissions prior to the 2019 maintenance year. Included in the analysis is a change in the Salt Lake County vehicle inspection and maintenance program that was adopted by the Utah Legislature that allows vehicles six years old and newer to be inspected every other year instead of annually. As the projections demonstrate, this change in the I/M program does not endanger attainment of the standard.

Table 3. Emissions Projections for Interim Years.

	Area	Mobile	Non-road	Point*	TOTAL
1993	15.34	295.21	34.84	0.00	345.39
2004	7.57	176.14	38.52	0.00	222.23
2005	7.54	168.66	39.23	0.00	215.43
2008	7.48	130.01	41.13	0.00	178.62
2011	7.50	118.19	43.08	0.00	168.77
2014	7.49	110.30	45.02	0.00	162.81
2017	7.42	106.35	47.01	0.00	160.78
2019	7.34	104.08	48.37	0.00	159.79

Note: Numbers may vary slightly from report due to rounding
Numbers may not add due to rounding
n/d = negative declaration
*There were no major CO point sources in the maintenance area in 1993; point source emissions are included in the Area Source inventory.

As Tables 1, 2 and 3 indicate, projections for 2019 CO emissions are below 1993 attainment year levels - there are 185.60 fewer tons of CO emitted each day in 2019 than in 1993 (345.39 tpd - 159.79 tpd = 185.60 tpd). Thus, maintenance of the CO NAAQS in Salt Lake City is demonstrated through 2019. Figure 1 illustrates how CO emissions sources change between 1993 and 2019.

IX.C.7.c Monitored Data

Salt Lake City has never measured an exceedance of the National Ambient Air Quality Standard of 35 ppm (one-hour average). A violation of the eight-hour standard occurs when the 2nd highest monitored value at a monitoring site exceeds 9 ppm. Table 4 below displays the eight-hour monitored data for stations in Salt Lake City from the attainment year of 1993 through 2003. No violation of the eight-hour standard of 9 ppm has been measured during this period.

Table 4. 8- Hour Monitoring Data at Salt Lake City Stations 1993 - 2003 (in ppm)

	State Street #2		State Street #3		Hawthorne	
	Max	2nd High	Max	2nd High	Max	2nd High
1993	7.5	6.5				
1994	8.4	6.8	10	7.7		
1995	5.1	4.6	5.9	5.5		
1996			7.6	6.9		
1997			7.3	6.5	7.1	6.5
1998			6.4	5.7	6.1	5.2
1999			5.2	5.2	5.8	5.7
2000			5.1	5	5.2	4.9
2001			4.3	4.1	4.7	4.7
2002			3.9	3.8	3.7	3.7
2003			4.3	4.3	4.3	4.2

IX.C.7.d Mobile Source Carbon Monoxide Emissions Budget for Transportation Conformity

The transportation conformity provisions of section 176(c)(2)(A) of the CAA require regional transportation plans and programs to show that "...emissions expected from implementation of plans and programs are consistent with estimates of emissions from motor vehicles and necessary emissions reductions contained in the applicable implementation plan..."

The federal conformity rule (40 CFR Part 93, Subpart A) and its preamble (58 FR 62193) indicate that motor vehicle emission budgets must be established for the last year of the maintenance plan, and may be established for any years deemed appropriate. If the maintenance plan does not establish motor vehicle emissions budgets for any years other than the last year of the maintenance plan, the conformity regulation requires that a "demonstration of consistency with the motor vehicle emissions budgets must be accompanied by a qualitative finding that there are not factors which would cause or contribute to a new violation or exacerbate an existing violation in the years before the last year of the maintenance plan." (40 CFR 93.118(b)(2)(ii), August 15, 1997) The normal interagency consultation process required by the regulation establishes what must be considered in order to make such a finding.

For transportation plan analysis years following the last year of the maintenance plan (in this case 2019), a conformity determination must show that emissions are less than or equal to the maintenance plan's motor vehicle emissions budget(s) for the last year of the implementation plan. EPA's conformity regulation (40 CFR 93.124) also allows the implementation plan to quantify explicitly the amount by which motor vehicle emissions could be higher while still demonstrating compliance with the maintenance requirement. The implementation plan can then allocate some or all of this additional "safety margin" to the emissions budgets for transportation conformity purposes.

Salt Lake City Mobile Source CO Emissions Budgets

This plan retracts the emissions budgets for 2005 - 2016 that were included in the original Salt Lake City Carbon Monoxide Maintenance Plan submitted to EPA in 1996. These numbers were based on the emissions projections of an earlier version of the MOBILE model, and are no longer accurate. In this maintenance plan, the State is establishing transportation conformity motor vehicle emission budgets (MVEB) for 2005 and 2019, based on the current MOBILE6.2 model.

CO Emissions Budgets

As presented in Table 3, total 1993 emissions were 345.39 tons per day. In that year, the second-high monitored value was 6.5 ppm, as shown in Table 4.

As presented in Table 3, projected emissions for 2005 are 215.43. The difference between the 1993 total of 345.39 and the projection of 215.43 tpd for 2005, the documentable portion of the safety margin, is 129.96 tpd. WFRC has requested a Motor Vehicle Emissions Budget (MVEB) of 168.66 tons per day for 2005; the Air Quality Board is allocating an additional 109.96 tpd from the safety margin to the MVEB. The remaining 20 tpd from the safety margin is retained to allow for potential variations in emissions from non-road and area sources. Therefore, the MVEB for 2005 is 278.62 tons per day.

Projected emissions for 2019, shown in Table 3, total 159.79 tons per day. The difference between the 1993 total of 345.39 and the projection of 159.79 tpd for 2019, the documentable portion of the safety margin, is 185.60 tpd. WFRC has projected a need for 104.08 tons per day for 2019; the Air Quality Board is allocating an additional 174.54 tpd from the safety margin to the MVEB. The remaining 11.06 tpd from the safety margin is retained to allow for potential variations in emissions from non-road and area sources. Therefore the MVEB for 2019 is 278.62 tons per day.

These new MVEB will take effect for future transportation conformity determinations upon approval of this Maintenance Plan by EPA.

Pursuant to 40 CFR 93.102(b)(3), no further conformity determinations for the Salt Lake County CO maintenance area will be necessary after March 22, 2019.

IX.C.7.e Monitoring Network/Verification of Continued Attainment

Utah will continue to operate an appropriate air quality monitoring network of NAMS and SLAMS monitors in accordance with 40 CFR Part 58 to verify the continued attainment of the CO NAAQS, and will gain EPA approval before making any changes to the Salt Lake City monitoring network. If measured mobile source parameters (e.g., vehicle miles traveled, congestion, fleet mix, etc.) change significantly over time, DAQ will perform a saturation monitoring study to determine whether additional and/or re-sited monitors are necessary.

Annual review of the NAMS/SLAMS air quality surveillance system will be conducted in accordance with 40 CFR 58.20(d) to determine whether the system continues to meet the monitoring objectives presented in Appendix D of 40 CFR Part 58.

IX.C.7.f Contingency Provisions

Section 175A(d) of the Clean Air Act requires that the maintenance plan contain contingency provisions to ensure that the State will promptly correct any violation of CO NAAQS that occurs in the Salt Lake City attainment/maintenance area. Attainment areas are not required to have pre-selected contingency measures and this plan removes the regulatory requirement for Alternative Commuting Options as the primary contingency measure and an enhanced inspection and maintenance program as a secondary contingency measure.

The contingency plan should ensure that the contingency measures are adopted expeditiously once the need is triggered. The primary elements of the contingency plan involve the tracking and triggering mechanisms to determine when contingency measures are needed and a process for implementing appropriate control measures.

(1) Tracking

The tracking plan for Salt Lake City will consist of 1) CO monitoring by DAQ and 2) analysis of CO concentrations, VMT and population growth. In accordance with 40 CFR Part 58, DAQ will continue to operate and maintain a Salt Lake City carbon monoxide monitoring network. Since revisions to the region's transportation improvement programs are prepared every two years, and must go through the transportation conformity finding, this process will be used to periodically review progress toward meeting the mobile source emissions projections in this maintenance plan.

(2) Trigger and Response

Triggering of the contingency plan does not automatically require a revision of the SIP nor is Salt Lake City necessarily redesignated once again to nonattainment. Instead, DAQ will normally have an appropriate time-frame to correct the violation with implementation of one or more adopted contingency measures. In the event that violations continue to occur, additional contingency measures will be adopted until the violations are corrected.

Upon notification of a CO NAAQS exceedance, DAQ and WFRC will develop appropriate contingency measure(s) intended to correct a violation of the CO NAAQS standard. Information about historical exceedances of the standard, the meteorological conditions related to the recent exceedance(s), and the most recent estimates of growth and emissions will be reviewed. (Notification to the Salt Lake City government and to EPA, of any exceedance will generally occur within 30 days, but no more than 45 days.) This process will be completed within six months of the exceedance notification. If a violation of the CO NAAQS has occurred (a violation occurs when a second exceedance within one calendar year is recorded at a monitoring site), a public hearing process at the State and local level will begin. If the Air Quality Board agrees that the implementation of local measures will prevent further exceedances or violations, the Board may endorse or approve of the local measures without adopting State requirements. If, however, DAQ finds locally adopted contingency measures to be inadequate, DAQ will recommend to the Board that they adopt state-enforceable measures as deemed necessary to prevent additional exceedances or violations. Contingency measures will be adopted and fully implemented within one year of a CO NAAQS violation. Any state-enforceable measures will become part of the next revised maintenance plan submitted to EPA for approval.

(3) List of Potential Contingency Measures

The State, in consultation with the WFRC and Salt Lake City officials, will choose one or more of the following contingency measures. Measures will be chosen to bring the area back into compliance quickly, and to meet the specific needs of Salt Lake City. It is likely that no federal money will be available to fund the implementation of the selected contingency measure(s). Most, if not all, of the costs will be borne by local citizens and Salt Lake City, local industries, and state government agencies.

- A return to annual inspections for all vehicles. In the current plan, vehicles six years old and newer are required to be inspected every other year.

- Improving the current I/M program in the Salt Lake City area, such as:

  - increase the maximum repair cost limits or totally eliminate emissions test waivers for vehicles that have failed the test, as allowed by statute,

  - increase the stringency of vehicle cut points,

  - use of remote sensing to detect high emission vehicles. This option would be added to the current I/M requirements (i.e., no one vehicle currently required to be inspected would be allowed to skip the regular inspection). The primary purpose would be to identify dirty vehicles not registered or otherwise captured in the current program.

- Mandatory Employer-Based Travel Reduction Programs as allowed by statute.

- Other emission control measures appropriate for the area based on consideration of cost-effectiveness, CO emission reduction potential, economic and social considerations, or other factors that the State deems to be appropriate.

IX.C.7.g Subsequent Maintenance Plan Revisions

No maintenance plan revision will be needed after 2019, as that is the 20th year following EPA approval of the original maintenance plan. No further maintenance plan is needed after successful maintenance of the standard for 20 years. However, the State will update the Plan if conditions warrant.

State	Utah
State Agency	Department of Environmental Quality
Affected Area	Statewide
Regulation	Utah State Implementation Plan
Rule Number	Section IX, Part C - Carbon Monoxide
Rule Title	Section IX.C.8 Carbon Monoxide Maintenance Provisions for Ogden
State Effective Date	01/04/2005
State Adoption Date	11/03/2004
EPA Effective Date	11/14/2005
Notice of Final Rule Date	09/14/2005
Notice of Final Rule Citation	70 FR 54267
Comments	

Rule:

Utah IX Part C.8. Carbon Monoxide Maintenance Provisions Ogden.pdf

Carbon Monoxide Maintenance Provisions for Ogden

Section IX, Part C.8

Adopted by the Air Quality Board
November 3, 2004

Table of Contents

List of Tables and Figures

IX.C.8.a Background

The Environmental Protection Agency (EPA) approved a redesignation request and maintenance plan for Ogden on March 9, 2001 (66 FR 14078), effective May 8, 2001. The action, which was adopted by the Utah Air Quality Board on September 4, 1996, established an attainment year of 1992, demonstrated maintenance through 2007, provided for the continuation of the Weber County vehicle emission inspection and maintenance program, established a carbon monoxide mobile source emissions budget for a number of years for mobile sources (to be used in transportation conformity determinations), and established a contingency plan in the event a violation of the carbon monoxide standards or an exceedance of the 1992 planning cap was measured.

This revised maintenance plan provides for the continuation of the County's inspection and maintenance program as defined in Weber-Morgan District Health Department regulation, revises the emission inventories and maintenance demonstration, revises the on-road mobile source carbon monoxide attainment emissions inventory for 1992, adds mobile source emissions budgets for 2005 and 2021 and repeals budgets for other years, and revises the contingency plan.

IX.C.8.b Emission Inventories and Maintenance Demonstration

The emission inventories for the 1992 attainment year and the 2021 maintenance year are presented below in Tables 1 and 2. Each inventory accounts for the emission control programs effective during that period, and the following controls will continue to be implemented to ensure maintenance of the carbon monoxide standards through the year 2021.

- Federal Motor Vehicle Control Program.

- Stationary Sources. The Ogden attainment/maintenance area is subject to the Prevention of Significant Deterioration permitting requirements of R307-405, and the requirements of R307-401 and R307-403. R307-401:405 are already included in the State Implementation Plan. The maintenance plan makes no changes to these regulations.

- Automobile Inspection and Maintenance Program. SIP Section X, Vehicle Inspection and Maintenance Program, Part E, Weber County, adopted November 3, 2004, including Weber-Morgan District Health Department regulation adopted May 12, 2003. The program is set forth in SIP Section X.E., Weber County I/M Program, last approved by EPA on July 17, 1997 (see 62 FR 38213).

Both inventories represent emissions on a typical winter weekday during the peak carbon monoxide season (November through January for the respective year). These inventories use EPA-approved emissions modeling methods and the latest transportation data from the Wasatch Front Regional Council's (WFRC) 2004 - 2030 transportation plan found by the Federal Highways Administration on January 20, 2004, to conform to the State Implementation Plan. Demographic data was obtained from the Governor's Office of Planning and Budget. The inventories were developed by the Division of Air Quality (DAQ) in coordination with the WFRC. Detailed information on model assumptions and parameters for each source category are found in the Technical Support Document at Tab 2.

The 1992 inventory included in the original 1996 Maintenance Plan indicated total winter weekday emissions of 70.82 tons, with 63.93 tons (90% of the total) coming from on-road mobile sources. Table 1 below differs from that inventory because methodologies for collecting and estimating inventory data have changed since 1996. Therefore, the 1992 inventory has been re-calculated using current methods so that it can be compared with the projections for future years. Methodology changes are explained in the Technical Support Document at Tab 2. The principal factor is the difference between mobile source emission projections using the currently-approved MOBILE6.2 version of the model, compared to the now outdated MOBILE 5 version used in the 1996 submittal.

The newly-calculated 1992 inventory in Table 1 below indicates that total winter weekday emissions were 106.49 tons, with 93.50 tons (88%) coming from on-road mobile sources. Though the inventory appears to be considerably higher than the original inventory, it reflects the differences in the new MOBILE6.2 model; no additional emissions are included, and the monitoring data in Table 4 below indicate that ambient concentrations of carbon monoxide have declined since 1992. This Plan constitutes a maintenance demonstration for carbon monoxide in Ogden through 2021.

Tables 1 and 2 show the comparable inventories for 1992 and 2021. Figure 1 shows the proportion of carbon monoxide coming from each kind of source.

Table 1. 1992 Attainment Year Carbon Monoxide Emission Inventory for the Ogden Attainment/Maintenance Area

SOURCE CATEGORY			CO Emissions (in Tons per Winter Week Day)	
Area Sources				
	Agricultural Burning		n/d	
	Aircraft Maintenance		0.01	
	Coal Combustion - commercial		0.35	
	Coal Combustion-industrial		0.47	
	Coal Combustion-residential		0.02	
	Detonation		n/d	
	FirefighterTraining		n/d	
	Forest Fires		n/d	
	Natural Gas Combustion-commercial		0.19	
	Natural Gas Combustion-industrial		n/d	
	Natural Gas Combustion-residential		0.30	
	Oil Combustion-commercial		0.00	
	Oil Combustion-residential		0.00	
	Open Burning		n/d	
	Orchard Heaters		n/d	
	Structural Fires		0.02	
	Vehicle Fires		0.00	
	Wood Combustion		4.92	
			Total Area Sources	6.28
Mobile Sources				
	On-road Mobile		*Total On-road Mobile*	93.50
	Off-road Mobile			
		Aircraft	1.03	
		Railroad	0.05	
		Misc Non-road Equipment	5.63	
			Total Non-road Mobile	6.71
Point Sources*				0.00
			Total Ogden CO Emissions	**106.49**

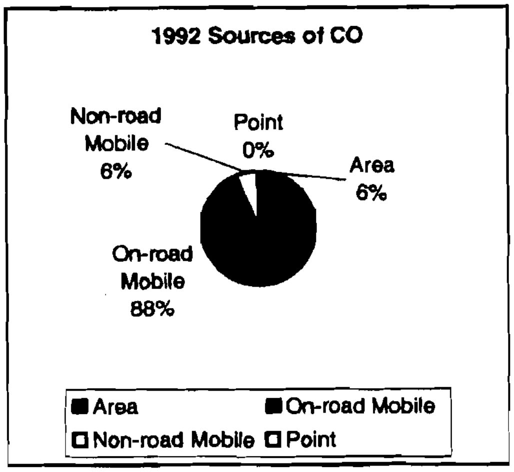
NOTE: Numbers may vary slightly from report due to rounding
Numbers may not add due to rounding.
n/d = negative declaration
* There were no major CO point sources in Ogden in 1992;
point source emissions are included in the Area Source inventory.

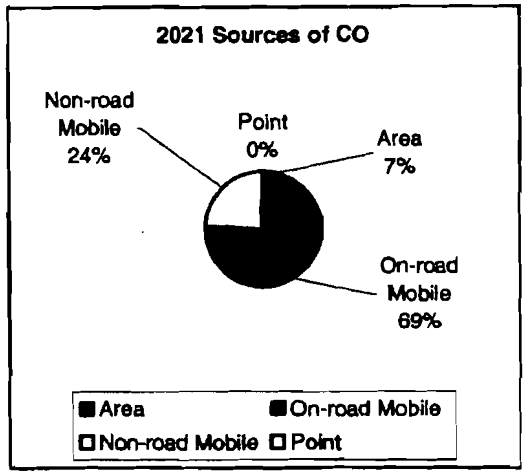
Table 2. 2021 Attainment Year Carbon Monoxide Emission Inventory for the Ogden Attainment/Maintenance Area

SOURCE CATEGORY				**CO Emissions** (in Tons per Winter Week Day)
Area Sources				
	Agricultural Burning		n/d	
	Aircraft Maintenance		0.02	
	Coal Combustion - commercial		0.32	
	Coal Combustion-industrial		0.43	
	Coal Combustion-residential		0.02	
	Detonation		n/d	
	FirefighterTraining		n/d	
	Forest Fires		n/d	
	Natural Gas Combustion-commercial		0.36	
	Natural Gas Combustion-industrial		n/d	
	Natural Gas Combustion-residential		0.35	
	Oil Combustion-commercial		0.00	
	Oil Combustion-residential		0.00	
	Open Burning		n/d	
	Orchard Heaters		n/d	
	Structural Fires		0.03	
	Vehicle Fires		0.01	
	Wood Combustion		1.57	
			Total Area Sources	3.09
Mobile Sources				
	On-road Mobile		*Total On-road Mobile*	29.47
	Off-road Mobile			
		Aircraft	1.73	
		Railroad	0.03	
		Misc Non-road Equipment	8.62	
			Total Non-road Mobile	10.38
Point Sources*				0.00
			Total Ogden CO Emissions	**42.94**

NOTE: Numbers may vary slightly from report due to rounding
Numbers may not add due to rounding.
n/d = negative declaration
* There were no major CO point sources in Ogden in 1992;
point source emissions are included in the Area Source inventory.

Figure 1. 1992 and 2021 CO Emission Sources in Ogden





DAQ also performed an analysis that shows the projected levels of emissions for the years 2004, 2005, 2008, 2011, 2014, 2017, 2020 and 2021 are below the 1992 attainment inventory, as shown in Table 3. The details are found in the Technical Support Document at Tab 2. These years were selected to demonstrate that Ogden will not experience an unexpected increase in emissions prior to the year 2021. Included in the analysis is a change in the Weber County vehicle inspection and maintenance program that was adopted by the Utah Legislature that allows vehicles six years old and newer to be inspected every other year instead of annually. As the projections demonstrate, this change in the I/M program does not endanger attainment of the standard.

Table 3. Emissions Projections for Interim Years
(Tons per Winter Week Day)

Year	Area	Mobile	Non-road	Point*	TOTAL
1992	6.28	93.50	6.71	0.00	106.49
2004	3.15	42.58	7.81	0.00	53.54
2005	3.14	44.54	7.99	0.00	55.67
2008	3.14	34.14	8.40	0.00	45.68
2011	3.16	32.07	8.82	0.00	44.05
2014	3.17	30.48	9.26	0.00	42.91
2017	3.15	29.72	9.72	0.00	42.59
2020	3.10	29.28	10.21	0.00	42.59
2021	3.09	29.47	10.38	0.00	42.94

NOTE: Numbers may vary slightly from report due to rounding
Numbers may not add due to rounding.
n/d = negative declaration
* There were no major CO point sources in Ogden in 1992;
point source emissions are included in Area Source inventory.

As Tables 1, 2 and 3 indicate, projections for 2021 CO emissions are below 1992 attainment year levels - there are 68.35 fewer tons of CO emitted each day in 2021 than in 1992 (106.49 tpd - 42.94 tpd = 63.55 tpd). Thus, maintenance of the CO NAAQS in Ogden is demonstrated through 2021. Figure 1 illustrates how CO emissions sources change between 1992 and 2021.

IX.C.8.c Monitored Data

Ogden has never measured an exceedance of the National Ambient Air Quality Standard of 35 ppm (one-hour average). A violation of the eight-hour standard occurs when the 2nd highest monitored value at a monitoring site exceeds 9 ppm. Table 4 below displays the eight-hour monitored data for stations in Ogden from the attainment year of 1992 through 2003. No violation of the eight-hour standard of 9 ppm has been measured during this period.

Table 4. 8-Hour Monitoring Data at the Ogden Station, 1992 - 2003
(ppm)

Year	Maximum	2nd High
1992	8.8	8.6
1993*	8.6	7.1
1994*	7.0	6.4
1995	7.9	6.7
1996	7.5	7.0
1997	7.6	6.4
1998	7.8	7.5
1999	6.4	6.2
2000	7.2	6.1
2001	6.2	4.9
2002	4.5	4.4
2003	4.1	4.1

* Partial years of data. The original monitoring site at 2955 South Washington Boulevard ended operations on April 6, 1993, because the building was torn down. The new location at 2540 South Washington Boulevard was approved by EPA and commenced operation on April 19, 1994.

IX.C.8.d Mobile Source Carbon Monoxide Emissions Budgets for Transportation Conformity

The transportation conformity provisions of section 176(c)(2)(A) of the CAA require regional transportation plans and programs to show that "...emissions expected from implementation of plans and programs are consistent with estimates of emissions from motor vehicles and necessary emissions reductions contained in the applicable implementation plan..."

The federal conformity rule (40 CFR Part 93, Subpart A) and its preamble (58 FR 62193) indicate that motor vehicle emission budgets must be established for the last year of the maintenance plan, and may be established for any years deemed appropriate. If the maintenance plan does not establish motor vehicle emissions budgets for any years other than the last year of the maintenance plan, the conformity regulation requires that a "demonstration of consistency with the motor vehicle emissions budgets must be accompanied by a qualitative finding that there are not factors which would cause or contribute to a new violation or exacerbate an existing violation in the years before the last year of the maintenance plan." The normal interagency consultation process required by the regulation establishes what must be considered in order to make such a finding.

For transportation plan analysis years following the last year of the maintenance plan (in this case 2021), a conformity determination must show that emissions are less than or equal to the maintenance plan's motor vehicle emissions budget for the last year of the implementation plan. EPA=s conformity regulation (40 CFR 93.124) also allows the implementation plan to quantify explicitly the amount by which motor vehicle emissions could be higher while still demonstrating compliance with the maintenance requirement. The implementation plan can then allocate some or all of this additional "safety margin" to the emissions budgets for transportation conformity purposes.

Ogden Mobile Source CO Emissions Budgets

This plan retracts the emissions budgets for 2005 - 2017 that were included in the original Ogden Carbon Monoxide Maintenance Plan submitted to EPA in 1996. These numbers were based on the emissions projections of an earlier version of the MOBILE model, and are no longer appropriate. In this maintenance plan, the State is establishing transportation conformity motor vehicle emission budgets (MVEB) for 2005 and 2021, based on the current MOBILE6.2 model.

CO Emissions Budget

As presented in Table 3, total 1992 emissions were 106.49 tons per day. In that year, the second-high monitored value was 8.6 ppm, as shown in Table 4.

As presented in Table 3, projected emissions for 2005 are 55.67. The difference between the 1992 total of 106.49 tpd and the projection of 55.67 tpd for 2005, the documentable portion of the safety margin, is 50.82 tpd. WFRC projects motor vehicle emissions of 44.54 tons per day for 2005; the Air Quality Board is allocating an additional 30.82 tpd from the safety margin to the Motor Vehicle Emissions Budget (MVEB). The remaining 20 tpd from the safety margin is retained to allow for potential variations in emissions from non-road and area sources. Therefore, the MVEB for 2005 is 75.36 tons per day.

Projected emissions for 2021, shown in Table 3, total 42.94. The difference between the 1992 total of 106.49 and the projection of 42.94 tpd for 2021, the documentable portion of the safety margin, is 63.55 tpd. WFRC projects motor vehicle emissions of 29.47 tons per day for 2021; the Air Quality Board is allocating an additional 43.55 tpd from the safety margin to the MVEB. The remaining 20 tpd from the safety margin is retained to allow for potential variations in emissions from non-road and area sources. Therefore the MVEB for 2021 is 73.02 tons per day.

These new MVEBs will take effect for future transportation conformity determinations upon approval of this Maintenance Plan or, for 2021, upon a finding of adequacy by EPA, whichever comes first.

Pursuant to 40 CFR 93.102(b)(3), no further conformity determinations for the Ogden CO maintenance area will be necessary after May 8, 2021.

IX.C.8.e Monitoring Network/Verification of Continued Attainment

Utah will continue to operate an appropriate air quality monitoring network of NAMS and SLAMS monitors in accordance with 40 CFR Part 58 to verify the continued attainment of the CO NAAQS and will gain EPA approval before making any changes to the Ogden monitoring network. If measured mobile source parameters (e.g., vehicle miles traveled, congestion, fleet mix, etc.) change significantly over time, DAQ will perform a saturation monitoring study to determine whether additional and/or re-sited monitors are necessary.

Annual review of the NAMS/SLAMS air quality surveillance system will be conducted in accordance with 40 CFR 58.20(d) to determine whether the system continues to meet the monitoring objectives presented in Appendix D of 40 CFR Part 58.

IX.C.8.f Contingency Provisions

Section 175A(d) of the Clean Air Act requires that the maintenance plan contain contingency provisions to ensure that the State will promptly correct any violation of the CO NAAQS that may occur in the Ogden attainment/maintenance area. Attainment areas are not required to have pre-selected contingency measures and this plan removes the regulatory requirement for Alternative Commuting Options and improvements in the Basic Vehicle Inspection and Maintenance Program as the primary contingency measures and an oxygenated gasoline program as a secondary contingency measure.

The contingency plan should ensure that the contingency measures are adopted expeditiously once the need is triggered. The primary elements of the contingency plan involve the tracking and triggering mechanisms to determine when contingency measures are needed and a process for implementing appropriate control measures.

(1) Tracking

The tracking plan for Ogden will consist of 1) CO monitoring by DAQ and 2) analysis of CO concentrations, VMT and population growth. In accordance with 40 CFR Part 58, DAQ will continue to operate and maintain an Ogden carbon monoxide monitoring site. Since revisions to the region's transportation improvement programs are prepared every two years, and must go through the transportation conformity finding, this process will be used to periodically review progress toward meeting the mobile source emissions projections in this maintenance plan.

(2) Trigger and Response

Triggering of the contingency plan does not automatically require a revision of the SIP nor is Ogden necessarily redesignated once again to nonattainment. Instead, DAQ will normally have an appropriate time-frame to correct the violation with implementation of one or more adopted contingency measures. In the event that violations continue to occur, additional contingency measures will be adopted until the violations are corrected.

Upon notification of a CO NAAQS exceedance, DAQ and WFRC will develop appropriate contingency measure(s) intended to correct a violation of the CO NAAQS standard. Information about historical exceedances of the standard, the meteorological conditions related to the recent exceedance(s), and the most recent estimates of growth and emissions will be reviewed.

Notification to the Ogden city government and to EPA, of any exceedance will generally occur within 30 days, but no more than 45 days following the exceedance. This process will be completed within six months of the exceedance notification. A violation occurs when a second exceedance within one calendar year is recorded at a monitoring site. If a violation of the CO NAAQS occurs, a public hearing process at the State and local level will begin. If the Air Quality Board agrees that the implementation of local measures will prevent further exceedances or violations, the Board may endorse or approve of the local measures without adopting State requirements. If, however, DAQ finds locally adopted contingency measures to be inadequate, DAQ will recommend to the Board that they adopt state-enforceable measures as deemed necessary to prevent additional exceedances or violations. Contingency measures will be adopted and fully implemented within one year of a CO NAAQS violation. Any state-enforceable measures will become part of the next revised maintenance plan submitted to EPA for approval.

(3) List of Potential Contingency Measures

The WFRC may choose one or more of the following contingency measures, or others that may be available at the time of a violation, to recommend to Ogden officials and the DAQ for consideration. WFRC will select contingency measures from the following list designed to bring the area back into compliance with the CO NAAQS quickly and that specifically meet the needs of Ogden. It is likely that no federal money will be available to fund the implementation of the selected contingency measure(s). Most, if not all, of the costs will be borne by local citizens and Ogden, local industries, and state government agencies.

- A return to annual inspections for all vehicles. In the current plan, vehicles six years old and newer are required to be inspected every other year.

- Improving the current I/M program in the Ogden area, such as increasing the maximum repair cost limits or totally eliminating emissions test waivers for vehicles that have failed the test.

- Mandatory Employer-Based Travel Reduction Programs as allowed by statute.

- Implementation of 2.7% oxygenated gasoline in Weber County from November 1 through the end of February, unless implementation would interfere with attainment of any other National Ambient Air Quality Standard.

- Other emission control measures appropriate for the area based on consideration of cost-effectiveness, CO emission reduction potential, economic and social considerations, or other factors that the State deems to be appropriate.

IX.C.8.g Subsequent Maintenance Plan Revisions

No maintenance plan revision will be needed after 2021, as that is the 20th year following EPA approval of the original maintenance plan. No further maintenance plan is needed after successful maintenance of the standard for 20 years. However, the State will update the Plan if conditions warrant.

Utah State Implementation Plan

Section IX, Part D

8-HOUR OZONE
MAINTENANCE PROVISIONS
FOR
SALT LAKE AND DAVIS COUNTIES

Adopted by the Air Quality Board

January 3, 2007

Table of Contents

List of Tables

List of Figures

List of Acronyms Used in this Document

ACT	Alternative Control Technique
AIRS	Aerometric Information Retrieval System (an EPA database)
AO	Approval Order
AQB	(Utah) Air Quality Board
BACT	Best Available Control Technology
BEIS2	Biogenics Emission Model
CAA	Federal Clean Air Act, amended in November 1990
CTG	Control Technique Guidance Document
CFR	Code of Federal Regulations
DAQ	Division of Air Quality
EDMS	Emissions and Dispersion Modeling System
EPA	U.S. Environmental Protection Agency
FHWA	Federal Highway Administration
HPMS	Highway Performance Monitoring System
I/M	Inspection and Maintenance Program for automobiles
KUC	Kennecott Utah Copper Corporation
LTO	Landing and Take Off
MACT	Maximum Achievable Control Technology, established under Title III of the CAA
MNR	Monitoring Network Review
MOBILE6	A model for mobile source emissions
MPO	Metropolitan Planning Organization
MSA	Metropolitan Statistical Area
MSW	Municipal Solid Waste
NAAQS	National Ambient Air Quality Standards
NAMS	National Air Monitoring Station
NO_x	Oxides of Nitrogen
NONROAD	A model for non road source emissions
NSR	New Source Review
PM_{10}	Particulate matter with an aerodynamic diameter of less than 10 microns
RACT	Reasonably Available Control Technology
RVP	Reid Vapor Pressure
SBAP	Small Business Assistance Program
SIP	State Implementation Plan
SLAMS	State and Local Air Monitoring Station
T/D	Tons per Day
T/Y	Tons per Year
TSD	Technical Support Document
UDOT	Utah Department of Transportation
UDEQ	Utah Department of Environmental Quality
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
WFRC	Wasatch Front Regional Council

D. OZONE MAINTENANCE PLAN

1. Introduction

The State of Utah has developed this maintenance plan for the 8-hour National Ambient Air Quality Standard (NAAQS) in accordance with Section 110(a)(1) of the Clean Air Act (CAA). Salt Lake and Davis Counties were found to be in attainment on July 18, 1995 (60 FR 36723) under the 1-hour ozone NAAQS and have been operating under an approved maintenance plan (62 FR 38213) since July 17, 1997. This maintenance plan demonstrates that Salt Lake and Davis Counties have achieved the 8-hour ozone standard and can maintain compliance with the standard through 2014. The remainder of the State of Utah is currently designated unclassifiable/attainment.

a. Maintenance Plan Overview

This maintenance plan uses an emission inventory approach and demonstrates that projected future emissions will be less than base year emissions. Emission inventories used in this maintenance plan were developed for an actual typical summer day using 2002 as the base year with projections for the years 2005, 2008, 2011, and 2014.

Federal approval of this maintenance plan is necessary to enable the State of Utah to maintain its ozone attainment/maintenance designation under the new 8-hour NAAQS.

b. Historical Background

The original CAA required areas failing to meet the federal ambient ozone standard to develop State Implementation Plans (SIP) with sufficient control requirements to expeditiously attain and maintain the standard. In 1977, Weber, Davis, Utah and Salt Lake Counties were designated non-attainment for ozone. In 1981 the EPA re-designated Weber and Utah Counties as attainment for ozone. In April of 1981, an ozone SIP was submitted to EPA that demonstrated attainment of the standard for both Davis and Salt Lake Counties by May 1, 1984. This ozone SIP submittal was fully approved by the EPA.

In November of 1990, Congress amended the Federal CAA. As a result, Salt Lake and Davis Counties were designated as "moderate" non-attainment areas based on ambient monitoring data for 1988 and 1989. On November 12, 1993 Utah submitted a formal request to EPA that the Salt Lake/Davis County non-attainment area be re-designated to attainment of the NAAQS, and the State, in accordance with the Act, submitted a maintenance plan. In June of 1994, on the basis of a reorganized state submittal and a parallel processing request, EPA issued a finding of "completeness" effective May 12, 1994. On January 5, 1995, the Ozone Maintenance Plan for Salt Lake and Davis Counties was revised. In April of 1995 volatile organic compound (VOC) Reasonably Available Control Technology (RACT) commitments were updated and in August of 1995 the contingency measures were revised to be consistent with language in the 1990 amended CAA.

By March of 1996, the Utah Division of Air Quality (DAQ) had obtained 1994 inventory data and had developed a more realistic methodology for projecting non-road emissions. Since there were no violations or exceedances of the ozone standard in 1994, and since there existed sufficient inventory data, DAQ prepared a new revision of the plan in which 1994 was established as the attainment year inventory for the demonstration of maintenance through the year 2007. The Utah Air Quality Board (AQB) adopted this revision on June 5, 1996.

By October of 1996, both Salt Lake and Davis Counties had finalized the details of the improvements to their vehicle inspection and maintenance (I/M) programs, which would be fully implemented in 2000 and 1998 respectively. The maintenance plan was revised to reflect the actual I/M programs that would be used in the area. The State also requested an exemption from additional oxides of nitrogen (NO_x) RACT requirements under section 182(f) of the CAA because the area had already attained the ozone standard and additional reductions were not needed to show maintenance of the standard. In July of 1997, the EPA approved the Ozone Maintenance Plan and NO_x RACT exemption for Salt Lake and Davis Counties, effective August 18, 1997, and re-designated both counties to attainment for ozone.

In July of 1997, the EPA established a new, more rigorous standard for ozone. The new 8-hour standard was set at a level of 0.08 parts per million (ppm) averaged over an eight-hour period. To take into account extreme and variable meteorological conditions that can influence ozone formation, a violation of the standard occurs when the three-year average of the fourth-highest, maximum value at a monitor exceeds the federal standard. Due to numerical rounding conventions, a violation occurs when the three-year average of the 4th highest daily 8-hour average ozone concentration is equal to or greater than 0.085 ppm.

On April 30, 2004 (69 FR 23951), EPA published the first phase of its final rule (Phase I Rule) to implement the 8-hour ozone NAAQS. At the same time EPA also published 8-hour ozone designations for all areas of the country. All areas of Utah were designated attainment or unclassifiable. These designations became effective on June 15, 2004. The Phase I rule provided that the 1-hour ozone NAAQS would no longer apply (i.e. be revoked) one year following the effective date of the 8-hour ozone NAAQS, or June 15, 2005. This revocation action was affirmed at 70 FR 44470 on August 3, 2005.

EPA issued final guidance for the development of the 8-hour ozone CAA Section 110(a)(1) maintenance plan on May 20, 2005. On November 29, 2005, EPA published the "Final Rule to Implement the 8-hour Ozone National Ambient Air Quality Standard (NAAQS) - Phase II." (70 FR 71611)

This maintenance plan was developed in accordance with the guidance and directions included therein.

2. Attainment Emission Inventory

Requirements relating to Attainment Emission Inventory:

- *The state can choose to demonstrate maintenance of the NAAQS using an emissions inventory approach. This approach requires the development of an "attainment emission inventory" to identify the level of emissions in the area that are sufficient to maintain the standard.*

- *The attainment emission inventory should be consistent with EPA guidance, and should include emissions during the time period associated with the monitoring data showing attainment. EPA recommended using the 2002 emission inventory.*[1]

Ozone is a gas composed of three oxygen atoms. Ozone at ground level, where it can be inhaled, is a pollutant. It is rarely emitted directly into the air, but rather is the result of a complex chemical reaction between volatile organic compounds (VOC) and oxides of nitrogen (NO_x) These compounds, when combined in the presence of intense sunlight, may cause ground-level ozone to form in harmful concentrations in the air.

$$\textbf{VOC} + \textbf{NO}_\textbf{x} \xrightarrow{\textbf{(Sunlight)}} \textbf{Ozone}$$

This SIP is based on emission inventories of VOC and NO_x, and documents that future emission levels of these precursors to ozone will be lower than present levels. As recommended by the EPA, the State of Utah has chosen to use 2002 as the attainment base year for this maintenance plan. An emission inventory for 2002 was developed to provide a base from which to evaluate future emissions. The emissions inventory is divided into four major source categories: point sources, area sources, mobile sources, and naturally occurring biogenic sources. Mobile sources are further divided into on-road and non-road categories. A short discussion of each of these categories will follow after Figure 2. A more in-depth discussion of each category is included in the Emission Inventory section of the Technical Support Document (TSD).

As required by EPA, DAQ applied rule effectiveness based on the revised rule effectiveness guidance found in Appendix B of EPA-454/R-005-01 entitled "Emissions Inventory Guidance of Ozone and Particulate Matter National Ambient Air Quality Standard (NAAQS) and Regional Haze Regulations." Rule effectiveness is a measure of the ability of the regulatory program to achieve all of the emission reductions possible by full compliance with applicable rules at all covered sources at all times. It reflects the assumption that rules are not typically 100 percent effective at all times.

A summary of the emission inventory for the 2002 base year with interim projections to 2014 is represented in Tables 1 and 2 for a typical summer day during the ozone season (June – August). Figures 1 and 2 represent relative percentages of 2002 emissions by source type. The 2002

[1] Each subdivision of this Plan begins with a summary of the requirements set forth in EPA's *Maintenance Plan Guidance Document for Certain 8-hour Ozone Areas Under Section 110(a)(1) of Clean Air Act*, May 20, 2005.

emission inventory, in its entirety, is included in the TSD. A graphical depiction of the emission projections for 2005-2014 and the maintenance demonstration can be found in the next subsection of this plan.

Table 1. Salt Lake and Davis Counties Source Category Totals for VOC (tons/day)

VOC	2002	2005	2008	2011	2014
Point Source	11.24	11.21	11.66	11.96	12.36
Area Source	89.32	92.42	96.30	101.86	107.75
Biogenic Source	120.26	120.26	120.26	120.26	120.26
Mobile On Road	57.66	44.70	35.36	29.11	24.52
Non-Road	29.55	25.47	20.90	18.42	16.57
Total (tons/day)	308.03	294.06	284.48	281.61	281.46
Attainment	308.03	308.03	308.03	308.03	308.03

Figure 1. Salt Lake and Davis Counties 2002 Source Percentage of VOC

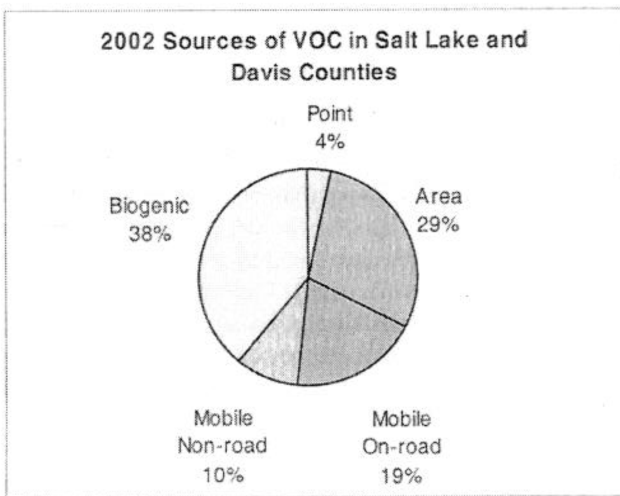
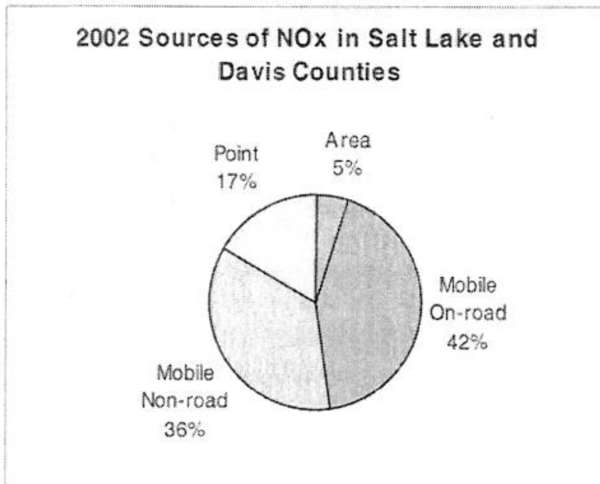


Table 2. Salt Lake and Davis Counties Source Category Totals for NOx (tons/day)

NOx	2002	2005	2008	2011	2014
Point Source	39.27	38.09	37.78	36.75	36.82
Area	11.36	10.08	10.79	11.82	12.82
Mobile On-Road	98.89	85.52	65.47	49.45	35.92
Non-Road	83.87	80.35	72.56	63.48	51.30
Total	233.39	214.04	186.60	161.50	136.86
Attainment	233.39	233.39	233.39	233.39	233.39

Figure 2. Salt Lake and Davis Counties 2002 Source Percentage of NOx



a. Point Source Emissions

Sources included in the point source portion of the attainment year inventory include all stationary sources with actual annual emissions of 100 tons or more of VOC or NO_x. Stationary sources with 2002 actual annual emissions of less than 100 tons of VOC or NO_x were included in the area source portion of the inventory. The 2002 emissions inventory for stationary point sources is based on actual activity levels during the peak ozone season and reflects estimated actual emissions. Actual annual emission data were used from applicable facilities to met the triennial emissions reporting requirement of EPA's Consolidated Emission Reporting Rule (CERR). These emissions were then converted from tons per year to tons per day and adjusted to reflect current rule effectiveness.

b. Area Source Emissions

The area source inventory estimates VOC and NO_x emissions by county. This inventory includes sources whose annual emissions from any single source location are less than 100 tons for VOC or NO_x. Non-road mobile source emissions such as aircraft maintenance and engine emissions, railroad switch engine and line-haul emissions, and miscellaneous emissions from all other non-road sources are included in the area source inventory, but reported separately as the non-road emission inventory as discussed below. The area source inventory was examined for double counting of emissions already included in the state's point source inventory and adjusted accordingly. All emission estimates in the area source inventory were reported in tons-per-peak-ozone-season day to reflect conditions most typical of higher ozone concentrations.

Area source emissions include small stationary sources such as gasoline stations and degreasing operations that are controlled through VOC regulatory rules. VOC emissions from vehicle refueling are also included in the area source emissions inventory. In compliance with EPA guidance, emission estimates for area sources covered by existing rules were adjusted to reflect current rule effectiveness guidance. These categories included asphalt paving, yard waste burning, municipal solid waste (MSW) burning, and gasoline transport vehicles.

c. Mobile Source Emissions

Emissions from on-road mobile sources include all VOC and NO_x from automobiles, trucks, and motorcycles designed for travel on established federal, state, or local roads. Calculated emissions from these vehicles are in the form of tailpipe exhaust, evaporation from the engine and fuel systems, and any other vapor losses during the running and resting of the vehicles.

Emissions from non-road mobile sources include tailpipe exhaust, evaporation from the engine and fuel systems of vehicles and construction equipment operated on unpaved roads, exhaust emissions or vapor losses resulting from the operation of railroad locomotives, airplanes, recreational, lawn and garden equipment, and from any other portable petroleum-fueled equipment.

VOC refueling emissions resulting from vehicle refueling at gasoline, ethanol, or natural gas stations are considered area emissions.

(1) On-Road Emissions. The on-road emissions inventory was generated by combining VOC and NO_x emission factors with estimates of peak summer weekday vehicle miles traveled (VMT) in Salt Lake and Davis Counties. Calculated on-road mobile emissions are aggregated by county for a peak ozone weekday. Details on the methodology used to compute emission estimates for the on-road mobile source inventory are delineated in the on-road emission inventory TSD.

Emission factors were derived from the EPA's mobile sources emissions model, MOBILE6 that provides emission factors for vehicle exhaust tailpipe emissions and evaporative emissions. The September 2003 version of MOBILE6, MOBILE6.1/6.2, incorporates the current federal tailpipe standards required by the CAA. It allows users to input local parameters that describe the vehicle fleet, vehicle emission control programs, the road network, fuel properties and meteorological conditions for the peak ozone weekday.

All MOBILE6 parameters involving I/M and the anti-tampering programs were measured, estimated, or confirmed by the Salt Lake County and Davis County Health Departments who administer these programs in their respective jurisdictions.

Utah Department of Transportation (UDOT) staff issues an annual report entitled *VMT by Functional Class*. This summary report tabulates actual VMT in average-annual-daily traffic. VMT is obtained from the Highway Performance Monitoring System (HPMS) database and reports VMT for twelve functional roadway classes in each city and county in the state. The Wasatch Front Regional Council (WFRC) regroups UDOT VMT from twelve to four classes; freeway, ramp, arterial, and local roads. The WFRC Travel Demand Model adjusts the annual average daily VMT to average-summer-weekday VMT using conversion factors provided within the model. The conversion factors and methods are explained in the TSD for on-road mobile sources.

Since the HPMS model does not estimate vehicle speeds, the WFRC supplied vehicle speed estimates for 2002 using the most recent population, employment, travel, road network, and traffic congestion data.

(2) Non-Road Emissions. Emissions from non-road mobile sources include releases from railroad locomotives, airplanes, recreational vehicles, construction equipment, lawn and garden equipment, and any other non-road petroleum-fueled vehicle or equipment.

(a) Trains. The two railroad companies operating within Salt Lake and Davis Counties submitted reports of their locomotive activities. Line-haul activity was reported in terms of fuel usage while yard activity was reported in terms of number of yard locomotives. These data were combined with emission factors published in EPA's "Procedures for Emission Inventory Preparation, Volume IV: Mobile Sources" (EPA 420-R-92-009) to estimate peak-ozone-day emissions.

(b) Aircraft Engines. The WFRC studied and summarized the airport activity of commercial, military, and private aircraft at each airport within the Salt Lake and Davis County area. They reported landing and take off (LTO) counts for specific aircraft types. To further refine commercial aircraft emissions, the publication *Airport Activity Statistics of Certificated Route Air Carriers* provided an itemized list of aircraft makers, models and the number of flights. Using the EPA/FAA Emission and Dispersion Modeling System (EDMS) version 4.04 software package, emissions of VOC and NO_x per LTO were calculated. The numbers of LTOs during an ozone day were estimated to produce peak-ozone-day emissions.

(c) Other Non-Road Engines. This section presents the 2002 base year inventory of emissions from non-road engines other than trains and airplanes. Emissions were estimated for each of 212 non-road engine categories and then totaled. Emissions from non-road engine categories associated with the construction, manufacturing, mining and agricultural industries were based on EPA NONROAD version 2004.

d. Biogenic Emissions

Biogenic emissions are natural VOC losses from forests, field crops, and all other plant matter growing or decomposing within the maintenance area. These emissions were calculated using EPA's BEIS 3.12 model, and incorporated into the emissions inventory for Salt Lake and Davis Counties. Based on future long-range land use planning for the area, these emissions are forecast to remain relatively constant throughout the period covered by this maintenance plan.

3. Maintenance Demonstration

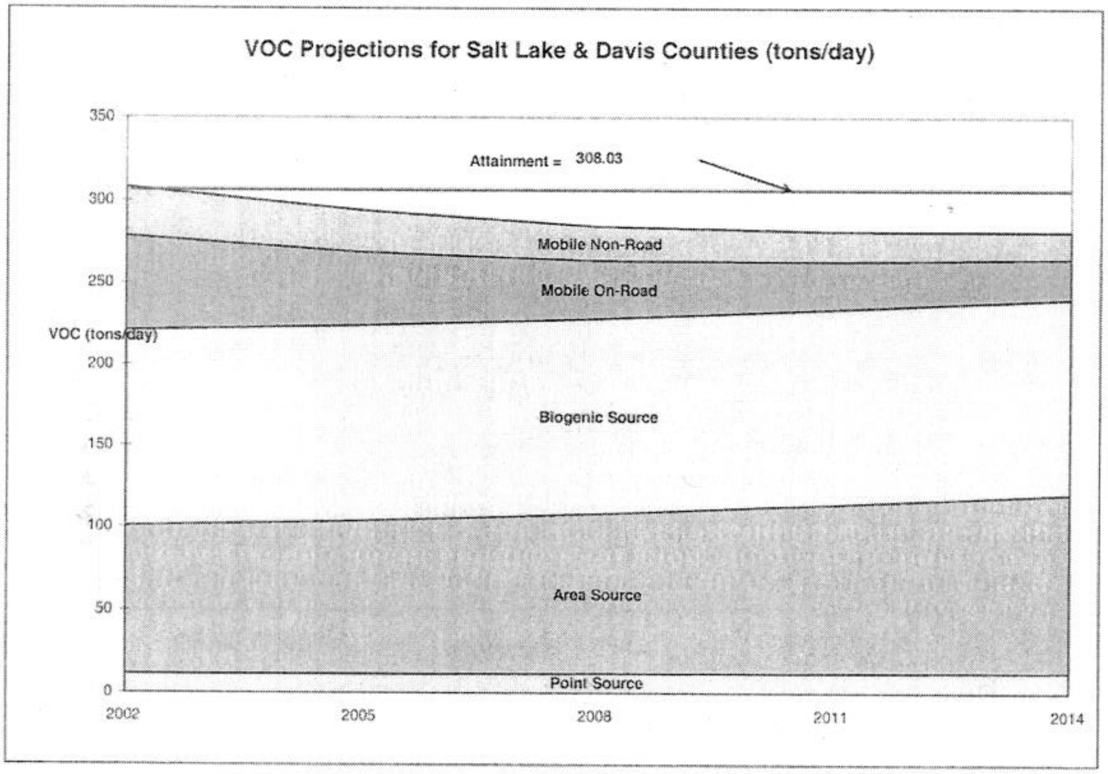
Requirement relating to Maintenance Demonstration:

- *A Maintenance Demonstration is a compilation of Projection inventories that demonstrate how an area will remain in compliance with the 8-hour ozone standard for the ten-year period following the effective date of designation as unclassifiable or attainment. For areas with an effective date of designation for the 8-hour NAAQS of June 15, 2004, the end projection year shall be 2014 and must show attainment.*

a. Base Year and Projected Emission Inventories

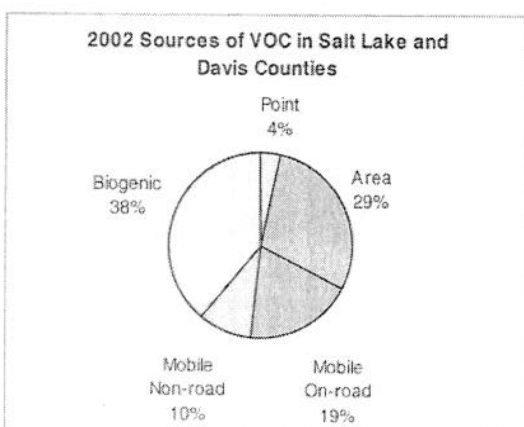
The attainment emission inventory reported in section IX.D.2 documents a level of emissions in Salt Lake and Davis County that is sufficient to maintain the 8-hour NAAQS for ozone through 2014. Emissions projections for each source category are used to determine if expected emission levels in future years will exceed the 2002 attainment emission inventory level. Maintenance of the NAAQS is demonstrated if the projected emissions remain below the 2002 level. Figures 3 and 5 graphically demonstrate that the projected VOC and NO_x emission inventories remain below the 2002 level, through the year 2014. Summary tables showing VOC and NO_x peak ozone season daily emissions in tons/day are included in the TSD.

Figure 3. VOC Projections through 2014 for Salt Lake and Davis Counties (tons/day)



Figures 4 and 6 give a pictorial look at the sources of VOC and NO_x for the attainment year of 2002 and the end projection year of 2014.

Figure 4. Salt Lake and Davis Counties 2002 and 2014 VOC Sources



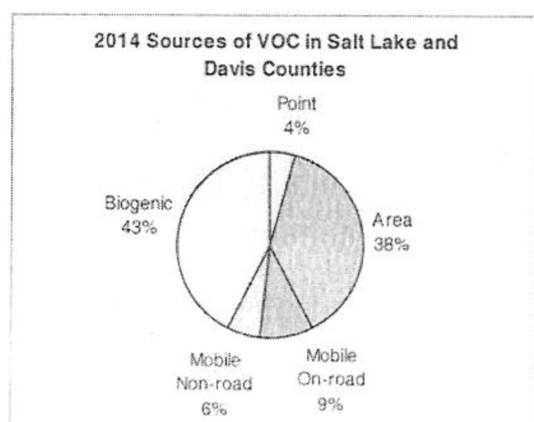


Figure 5. NO_x Projections through 2014 for Salt Lake and Davis Counties (tons/day)

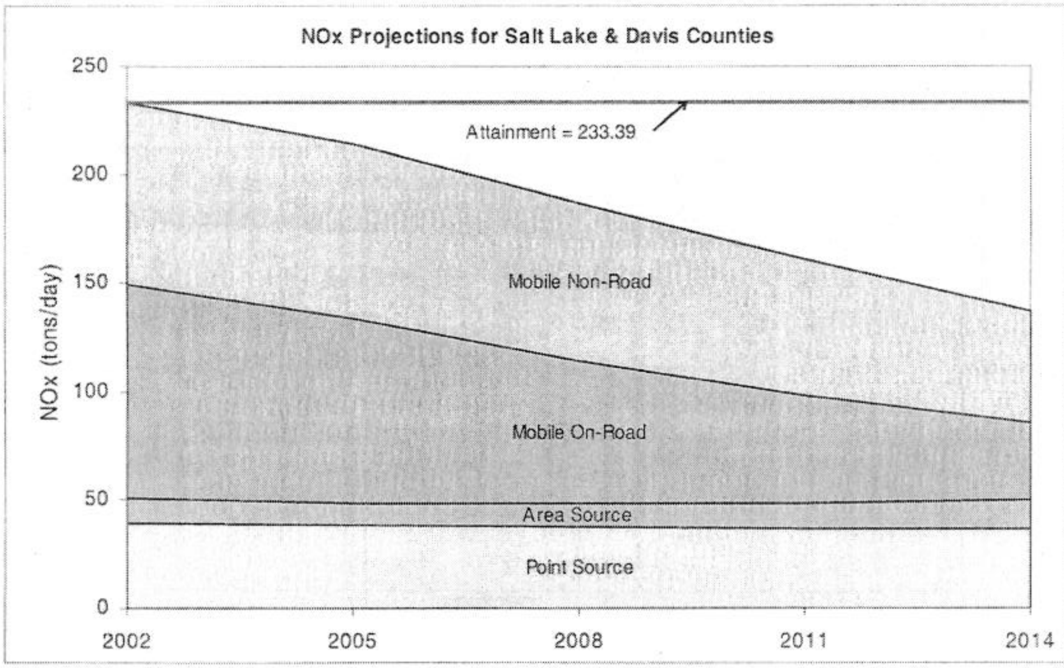
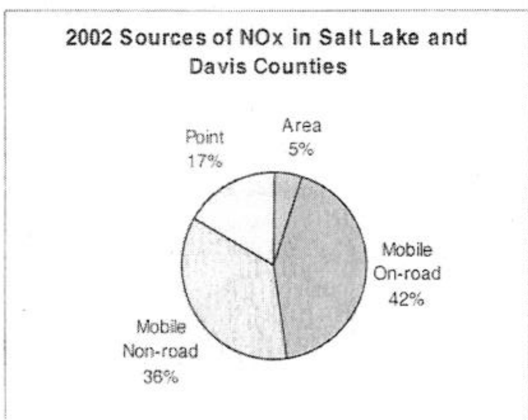
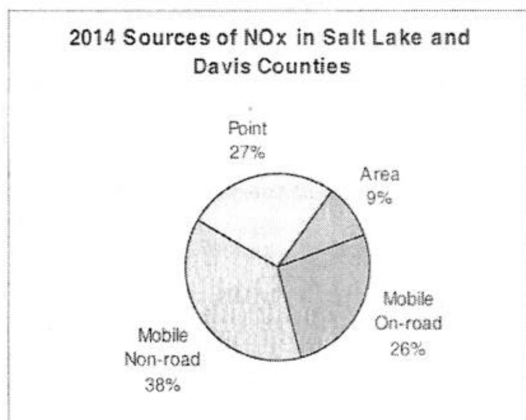


Figure 6. Salt Lake and Davis Counties 2002 and 2014 NO_x Sources





The Utah DAQ will track the progress of this maintenance plan by periodically reviewing future emission inventories to verify that emission levels of VOC and NO_x do not surpass those presented in Subsection 2 above.

A short discussion of how emissions were projected for each of the major source categories follows. Additional discussion is provided in the Emission Inventory section of the TSD.

b. Methodology for Projecting Emissions

(1) Point Sources. Employment growth factors published by the Demographic and Economic Analysis section of the Governor's Office of Planning and Budget were used to project point source emissions.

The point source attainment year inventory contains a listing of emissions by individual sources that compose each plant's actual emissions. The reliability of these projections is reinforced by the continued maintenance of existing rules (R307-325 through 342) that regulate the operations of all VOC sources in Salt Lake and Davis Counties. The New Source Review (NSR) rules that specify pollution control requirements for any new sources or modifications to existing sources also reinforce the reliability of this emission projection inventory.

(2) Area Sources. Growth factors for estimating end projection year emissions for area sources were based on the most recent population and sector-specific employment growth data published by the Governor's Office of Planning and Budget.

(3) Mobile Sources. Projected mobile source emissions were broken down into on-road and non-road categories described below.

(a) On-Road Emissions. Projected on-road emissions for future years are generated by combining VOC and NO_x emission factors with projections of average summer weekday vehicle miles traveled (VMT) within Salt Lake and Davis Counties. VMT projections are obtained from the WFRC Travel Demand Model.

(b) Non-Road Emissions. Projected non-road emissions were broken down into railroad engines, aircraft engines, and miscellaneous non-road equipment categories as described below.

(i) Railroad Engines. Growth factors for estimating projection year emissions are based on industrial employment growth derived from the Governor's Office of Planning and Budget. Emissions were estimated to increase at the rate of employment growth within the Transportation, Communications, and Public Utilities segments of industry.

(ii) Aircraft Engines. Growth figures for all aircraft emissions in Salt Lake and Davis Counties were provided by the Wasatch Front Regional Council (WFRC). These growth figures are applied to the daily emissions calculated in the 2002 attainment inventory to obtain emissions projections through 2014.

(iii) Miscellaneous Non-Road Equipment. EPA's NONROAD version 2004 software was run for all projection years.

(4) Biogenic Emissions. Biogenic emissions will remain constant in Salt Lake and Davis Counties unless significant changes occur in land use, which is not anticipated. The typical

summer day emissions were calculated by taking the average of June, July, and August total emissions.

4. Monitoring Network/Demonstration of Continued Attainment

Requirement related to Ozone Monitoring:

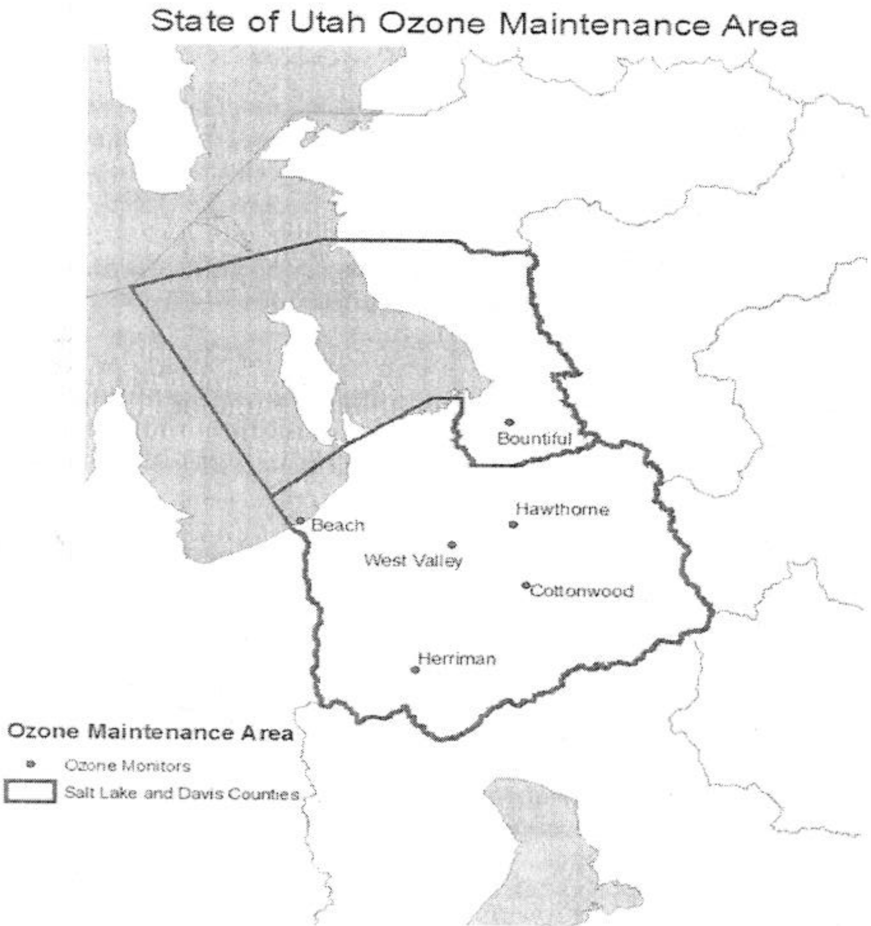
- *Three consecutive years of Ozone monitoring data must show that violations of the standard have not occurred. The standard is the annual fourth-highest daily maximum 8-hour ozone concentration, expressed in parts per million, averaged over three years. Thus the three-year average of the annual fourth-highest daily 8-hour average ozone concentration must not exceed 0.08 ppm to meet the standard. Due to rounding conventions, the fourth-highest daily 8-hour average ozone concentration may not exceed 0.084 ppm.*

a. Ozone Monitoring Network

Information regarding ozone monitoring in Utah is included in the Monitoring Network Review (MNR). Since the early 1980s the MNR has been updated annually and submitted to the EPA for approval. EPA personnel have concurred with the annual network reviews and agreed that the network is adequate. They have also visited the monitoring sites on several occasions to verify compliance with federal siting requirements. The ozone monitoring season in Utah is May through September (40 CFR Part 58, Appendix D, 2.5). The highest ozone values usually occur during the months of June, July and August.

The valley setting of Salt Lake and Davis Counties complicates ozone monitoring of the major urban area along the Wasatch Front. Typical ozone monitoring at sites on flat terrain in wide-open spaces find the peak ozone monitoring station located 5 – 7 hours down wind from the urban area. Because Salt Lake and Davis Counties have a large body of water on their west side (Great Salt Lake) and a major mountain range (Wasatch) on their east side, summer wind patterns result in a diurnal on-shore/off-shore wind flow. This pattern suggests that after 5 – 7 hours the polluted air mass may in fact return to the urban area where the ozone precursors originated. Figure 7 depicts the relative locations of the ozone-monitoring network within Salt Lake and Davis Counties.

Figure 7. Ozone Monitoring Network within Salt Lake and Davis Counties



The following ozone monitoring stations were operating in Salt Lake and Davis Counties during the period 1999 through 2005. Pertinent ozone monitoring station data is delineated below with additional information in the TSD.

Beach (AIRS ID #49-035-2004). This site is located at the Great Salt Lake Marina close to the western border of Salt Lake County. The site has been in existence for many years to measure PM_{10} and SO_2. Ozone monitoring equipment was added to the site as a result of an ozone saturation study that showed high concentrations of ozone in this area. The ozone monitoring equipment began operating on May 17, 1994.

Bountiful (AIRS ID # 49-011-0004). In the city of Bountiful in Davis County, ozone has been measured at two different locations since February of 1975. On July 22, 2003 the

8-19

monitoring station was moved approximately three-quarters of a mile north to the current location at 171 West 1370 North on the grounds of Viewmont High School. The move was necessitated by the construction of a new city fire station on the original site. The new site is in a similar residential setting, centrally located and representative of a large part of the city of Bountiful.

Cottonwood (AIRS ID # 49-035-0003). Based on wind trajectories this site was determined to be the site that would measure the maximum ozone concentration in the Salt Lake area. It is located in a residential area approximately nine miles south of the Central Business District. Monitoring began at this site in December of 1980.

Hawthorne (AIRS ID # 49-035-3006). This site is located in a residential area near downtown Salt Lake City. It is representative of a large part of Salt Lake City. Monitoring began at this site on January 1, 1997.

Herriman (AIRS ID #49-035-3008). This site is located in the southwest corner of the Salt Lake Valley in a predominantly rural area. The site was added as a result of a 1993 ozone saturation study that showed high concentrations of ozone in this area. The ozone monitoring equipment began operating on May 1, 1994.

West Valley (AIRS ID # 49-35-3007). West Valley City is the second largest city in the State of Utah and is located in the north central area of the Salt Lake valley. This site was chosen to determine ozone concentrations in an area where a large percentage of the population is clustered. Monitoring at this site began on January 21, 1999.

b. Ozone Monitoring Data

Table 3 represents monitoring data for the Salt Lake and Davis County monitoring sites. For each site, the 4th maximum 8-hour ozone concentration along with the three-year average of the 4th maximum ozone concentration is presented.

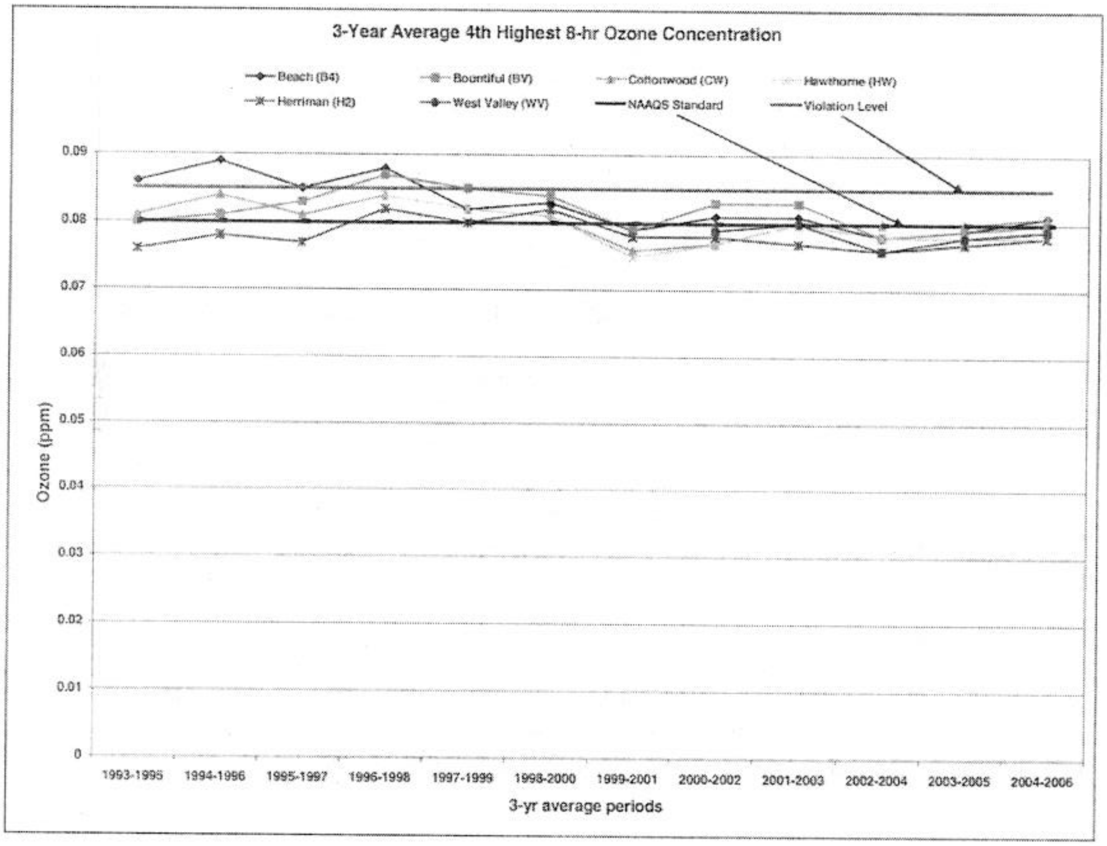
Table 3. Salt Lake and Davis Counties Individual Monitor 4th Highest Ozone and Three-Year Average 4th Highest Ozone Values* (ppm)

Monitoring Site	2000	2001	2002	2003	2004	2005	2000-02 8 hr avg	2001-03 8-hr avg	2002-04 8-hr avg	2003-05 8-hr avg
Beach	0.078	0.082	0.083	0.077	0.075	**0.086**	0.081	0.081	0.078	0.079
Bountiful	0.078	0.081	**0.089**	0.079	0.067	**0.092**	0.083	0.083	0.078	0.079
Cottonwood	0.072	0.076	0.082	0.083	0.074	0.084	0.077	0.080	0.080	0.080
Hawthorne	0.073	0.075	0.084	0.081	0.069	0.083	0.077	0.080	0.078	0.078
Herriman	0.081	0.076	0.078	0.076	0.074	0.080	0.078	0.077	0.076	0.077
West Valley	0.074	0.084	0.079	0.078	0.071	**0.085**	0.079	0.080	0.076	0.078
Avg 4th High	0.076	0.079	0.083	0.079	0.072	**0.085**	0.079	0.080	0.078	0.079

* ***Bold** values represent exceedance of National Ambient Air Quality Standard*

Figure 8 depicts the three-year 4th highest ozone concentration average trend since the 1993-1995 periods.

Figure 8. Three-Year Period Ozone Averages (1993-2005)



c. Review of Monitoring Network

The existing monitoring network for ozone consists of thirteen monitoring sites located primarily in the populated counties along the Wasatch Front. DAQ considers the present configuration appropriate to reflect the current source and population areas in Salt Lake and Davis Counties. The DAQ will gain EPA approval before making any changes to the current monitoring network configuration. The DAQ will continue to operate and maintain an adequate air quality monitoring network in accordance with 40 CFR 58, *Ambient Air Quality Surveillance*, to verify the continued attainment of the 8-hour ozone NAAQS. The DAQ will continue to conduct annual reviews of the ozone monitoring network in accordance with 40 CFR 58.20(d) to determine whether the system continues to meet the monitoring objectives presented in Appendix D of 40 CFR Part 58.

5. Existing Regulations and Controls

Requirements relating to existing regulations:

- *Anti-backsliding provisions established in 40 CFR 51.905(a)(4) ensure that emission control strategies that were implemented to address the 1-hour ozone standard are maintained when the area transitions to an 8-hour maintenance plan. The applicable requirements that are listed in 40 CFR 51.900(f) must be maintained, unless the state requests that these obligations be shifted to contingency measures.*

Utah has maintained the requirements in this plan as described below.

a. Reasonably Available Control Technology (RACT)

The State certifies that all existing RACT controls required in the 1981 Ozone SIP and 1-hour maintenance plan dated September 9, 1998, will remain in effect after approval of this SIP revision.

(1) VOC Sources Covered by a CTG issued after 1990 – CAA 182(b)(2). **Negative Declaration** - In the 1-hour maintenance plan, Utah determined that there were no VOC sources covered by a Control Technique Guideline (CTG) issued after 1990.

(2) VOC Sources Covered by a CTG issued before 1990. In the 1981 SIP and the 1-hour Maintenance Plan, dated September 9, 1998, the State of Utah established required controls under Section 182(b)(2) of the CAA. Utah is currently enforcing a set of RACT regulations that are based on CTGs developed by EPA. These state RACT regulations are implemented by the following rules in the Utah Administrative Code.

R307-325	General Requirements
R307-326	Control of Hydrocarbon Emissions in Refineries
R307-327	Petroleum Liquid Storage
R307-328	Gasoline Transfer and Storage
R307-335	Degreasing and Solvent Cleaning Operations
R307-340	Surface Coating Operations
R307-341	Cutback Asphalt
R307-342	Qualifications of Contractors and Test Procedures for Vapor Recovery Systems for Gasoline Delivery Tanks

(3) Major Stationary Sources that are not covered by a CTG. The State of Utah has identified the following major sources (100 t/y or more) of VOC emissions in the Salt Lake and Davis County attainment area. RACT for these major stationary sources that are not covered by specific CTGs or ACTs is listed below. In addition, NO_x emission limitations for most of these major sources are presented in Subsection IX.H.2 of the SIP.

E-22

Utah State Implementation Plan

Emission Limits and Operating Practices

Section IX, Part H

H.1 General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM_{10} Requirements

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.1 listed below, the terms and conditions of this Subsection IX.H.1 shall apply to all sources subsequently addressed in Subsection IX.H.2 and IX.H.3. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.2 and IX.H.3 shall take precedence.

b. Definitions.
   i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.

   ii. Natural gas curtailment means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment.

c. Recordkeeping and Reporting
   i. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request, and shall include a period of two years ending with the date of the request.

   ii. Each source shall comply with all applicable sections of R307-150 Emission Inventories.

   iii. Each source shall submit a report of any deviation from the applicable requirements of this Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted to the Director no later than 24-months following the deviation or earlier if specified by an underlying applicable requirement. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.

d. Emission Limitations.
   i. All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.

   ii. All emission limitations of PM_{10} listed in Subsections IX.H.2 and IX.H.3 include both filterable and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.

e. Stack Testing.

   i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and I.X.H.3 shall be performed in accordance with the following:
      A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved methods acceptable to the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.

C. PM_{10}: The following methods shall be used to measure filterable particulate emissions: 40 CFR 51, Appendix M, Method 201 or 201A, or other EPA-approved testing method, as acceptable to the Director. If other approved testing methods are used which cannot measure the PM_{10} fraction of the filterable particulate emissions, all of the filterable particulate emissions shall be considered PM_{10}.
The following methods shall be used to measure condensable particulate emissions: 40 CFR 51, Appendix M, Method 202, or other EPA-approved testing method, as acceptable to the Director.

D. SO_2: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.

E. NO_x: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.

F. Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.

G. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.

H. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.

f. Continuous Emission and Opacity Monitoring.

i. For all continuous monitoring devices, the following shall apply:

A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. Flow measurement shall be in accordance with the requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A.

B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.

ii. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.

g. Petroleum Refineries.

i. Limits at Fluid Catalytic Cracking Units (FCCU)
   A. FCCU SO_2 Emissions
      I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an SO_2 emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.
      II. Compliance with this limit shall be determined by following 40 C.F.R. §60.105a(g).
   B. FCCU PM Emissions
      I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis.
      II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) or 40 C.F.R. §60.104a(d) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every three (3) years at each FCCU.
      III. By no later than January 1, 2019, each owner or operator of an FCCU shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU for determination of source-wide PM_{10} emissions.

ii. Limits on Refinery Fuel Gas.
   A. All petroleum refineries in or affecting any PM2.5 nonattainment area or any PM_{10} nonattainment or maintenance area shall reduce the H2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.
   B. For natural gas, compliance is assumed while the fuel comes from a public utility.

iii. Sulfur Removal Units
   A. All petroleum refineries in or affecting any PM_{10} nonattainment or maintenance area shall require:
      I. Sulfur removal units/plants (SRUs) that are at least 95% effective in removing sulfur from the streams fed to the unit; or
      II. SRUs that meet the SO_2 emission limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2) as appropriate.
   B. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).
   C. Compliance shall be demonstrated by daily monitoring of flows to the SRU(s). Continuous monitoring of SO_2 concentration in the exhaust stream shall be conducted via CEM as outlined in IX.H.1.f above. Compliance shall be determined on a rolling 30-day average.

iv. No Burning of Liquid Fuel Oil in Stationary Sources
   A. No petroleum refineries in or affecting any PM nonattainment or maintenance area shall be allowed to burn liquid fuel oil in stationary sources except during natural gas curtailments or as specified in the individual subsections of Section IX, Part H.

B. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in standby or emergency equipment is exempt from the limitation of IX.H.1.g.iv.A above.

v. Requirements on Hydrocarbon Flares.

A. Beginning January 1, 2018, all hydrocarbon flares at petroleum refineries located in or affecting a designated PM_{10} nonattainment area or maintenance area within the State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if not already subject under the flare applicability provisions of Subpart Ja.

H.2 Source Specific Emission Limitations in Salt Lake County PM_{10} Nonattainment/Maintenance Area

a. Big West Oil Company

i. Source-wide PM_{10} Cap
By no later than January 1, 2019, combined emissions of PM_{10} shall not exceed 1.037 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.a.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Plant gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM10: 5.7 lb/MMscf

Fuel Oil: The PM_{10} emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42

FCC Stacks: The PM_{10} emission factor shall be established by stack test.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.a.i.A above apply until such time as stack testing is conducted as outlined below:

PM_{10} stack testing on the FCC shall be performed initially no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCCs to arrive at a combined daily PM_{10} emission total.

For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily gas consumption shall be measured by meters that can delineate the flow of gas to the boilers, furnaces and the SRU incinerator.

The equation used to determine emissions from these units shall be as follows:

Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The daily PM_{10} emissions from the FCC shall be calculated using the following equation:

$E = FR * EF$

Where:
E = Emitted PM_{10}
FR = Feed Rate to Unit (kbbls/day)
EF = emission factor (lbs/kbbl), established by the most recent stack test

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x Cap
By no later than January 1, 2019, combined emissions of NO_x shall not exceed 0.80 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.a.ii.B below, the default emission factors to be used are as follows:

Natural gas: shall be determined from the latest edition of AP-42
Plant gas: assumed equal to natural gas
Diesel fuel: shall be determined from the latest edition of AP-42

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.a.ii.A above apply until such time as stack testing is conducted as outlined below:

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed and the next stack test shall be performed within 3 years of the next stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.a.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide NO_x Cap shall be determined for each day as follows:

Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results.

Daily plant gas consumption at the furnaces, boilers and SRU incinerator shall be measured by flow meters. The equations used to determine emissions shall be as follows:

NO_x = Emission Factor (lb/MMscf)*Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Where the emission factor is derived from the fuel used, as listed in IX.H.2.a.ii.A above

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The daily NO_x emissions from the FCC shall be calculated using a CEM as outlined in IX.H.1.f

Total daily NO_x emissions shall be calculated by adding the results of the above NO_x equations for natural gas and plant gas combustion to the estimate for the FCC.

For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO_2 Cap
By no later than January 1, 2019, combined emissions of SO_2 shall not exceed 0.60 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows:

Natural Gas - 0.60 lb SO_2/MMscf gas

Plant Gas: The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM as outlined in IX.H.1.f. .

SRUs: The emission rate shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.1.f.

Fuel oil: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the fuel oil, as follows:

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt. % S/100 * (64 lb SO2/32 lb S)

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

The daily SO_2 emission from the FCC shall be calculated using the following equation:

SO2 = FG * (ADV/1,000,000) * (64 lb/mole) * (operating hours/day) / (2000 lb/ton)

Where:
FG = Flue Gas in moles/hour
ADV = average daily value from SO_2 CEM as outlined in IX.H.1.f

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H_2S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

v. Alternate Startup and Shutdown Requirements

A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO_2 shall not exceed 1.2 tons per day (tpd). For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

B. The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.

b. Bountiful City Light and Power: Power Plant

i. Emissions to the atmosphere shall not exceed the following rates and concentrations:

A. GT #1 (5.3 MW Turbine)
Exhaust Stack: 0.6 g NO_x / kW-hr

B. GT #2 and GT #3 (each TITAN Turbine)
Exhaust Stack: 7.5 lb NO_x / hr

ii. Compliance to the above emission limitations shall be determined by stack test. Stack testing shall be performed as outlined in IX.H.1.e.

A. Initial stack tests have been performed. Each turbine shall be tested at least once per year.

iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).

B. Shutdown begins with the initiation of the stop sequence of a turbine until the cessation of natural gas flow to the turbine.

C. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.

c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

i NO_x emissions from the operation of all engines at the plant shall not exceed 0.648 tons per day.

ii. Compliance with the emission limitation shall be determined by summing the emissions from all the engines. Emission from each engine shall be calculated from the following equation:

Emissions (tons/day) = (Power production in kW-hrs/day) x (Emission factor in grams/kW- hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)

A. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested at least every three years from the previous test.

B. The NO_x emission factor for each engine shall be derived from the most recent stack test.

C. NO_x emissions shall be calculated on a daily basis.

D. A day is equivalent to the time period from midnight to the following midnight.

E. The number of kilowatt hours generated by each engine shall be determined by examination of electrical meters, which shall record electricity production on a continuous basis.

d. Chevron Products Company

i. Source-wide PM_{10} Cap
By no later than January 1, 2019, combined emissions of PM_{10} shall not exceed 0.715 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.d.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Plant gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

HF alkylation polymer: shall be determined from the latest edition of AP-42 (HF alkylation polymer treated as fuel oil #6)

Diesel fuel: shall be determined from the latest edition of AP-42

Cooling Towers: shall be determined from the latest edition of AP-42

FCC Stack:
The PM10 emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.d.i.A above apply until such time as stack testing is conducted as outlined below:

Initial PM_{10} stack testing on the FCC stack has been performed and shall be conducted at least once every three (3) years from the date of the last stack test. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCC to arrive at a combined daily PM_{10} emission total. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equation used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x Cap
By no later than January 1, 2019, combined emissions of NO_x shall not exceed 2.1 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.d.ii.B below, the default emission factors to be used are as follows:

Natural gas: shall be determined from the latest edition of AP-42
Plant gas: assumed equal to natural gas
Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel oil #6)
Diesel fuel: shall be determined from the latest edition of AP-42

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.d.ii.A above apply until such time as stack testing is conducted as outlined below:

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has been performed and shall be conducted at least once every three (3) years from the date of the last stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.d.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide NO_x Cap shall be determined for each day as follows:

Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results.

A NO_x CEM shall be used to calculate daily NO_x emissions from the FCC. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the flow rate of the flue gas. The NO_x concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO_2 Cap
By no later than January 1, 2019, combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows:

FCC: The emission rate shall be determined by the FCC SO_2 CEM as outlined in IX.H.1.f.

SRUs: The emission rate shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.1.f.

Natural gas: EF = 0.60 lb/MMscf

Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the fuel oil, as follows:

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S)

Plant gas: the emission factor shall be calculated from the H2S measurement obtained from the H2S CEM.

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H2S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment and Alternative Fuels

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

B. HF alkylation polymer may be burned in the Alky Furnace (F-36017).

C. Plant coke may be burned in the FCC Catalyst Regenerator.

e. Hexcel Corporation: Salt Lake Operations

i. The following limits shall not be exceeded for fiber line operations:

A. 5.50 MMscf of natural gas consumed per day.

B. 0.061 MM pounds of carbon fiber produced per day.

C. Compliance with each limit shall be determined by the following methods:

I. Natural gas consumption shall be determined by examination of natural gas billing records for the plant and onsite pipe-line metering.

II. Fiber production shall be determined by examination of plant production records.

III. Records of consumption and production shall be kept on a daily basis for all periods when the plant is in operation.

ii. After a shutdown and prior to startup of fiber lines 13, 14, 15, or 16, the line's baghouse(s) shall be started and remain in operation during production.

A. During fiber line production, the static pressure differential across the filter media shall be within the manufacturer's recommended range and shall be recorded daily.

B. The manometer or the differential pressure gauge shall be calibrated according to the manufacturer's instructions at least once every 12 months.

f. Holly Refining and Marketing Company

i. Source-wide PM_{10} Cap
By no later than January 1, 2019, PM_{10} emissions from all sources shall not exceed 0.416 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.g.i.B below, the default emission factors to be used are as follows:

Natural gas or Plant gas:
non-NSPS combustion equipment: 7.65 lb PM_{10}/MMscf
NSPS combustion equipment: 0.52 lb PM_{10}/MMscf

Fuel oil:
The filterable PM_{10} emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

PM_{10} (lb/1000 gal) = (10 * wt. % S) + 3.22

The condensable PM_{10} emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:
The PM_{10} emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

B. The default emission factors listed in IX.H.2.g.i.A above apply until such time as stack testing is conducted as outlined below:

Initial stack testing on all NSPS combustion equipment shall be conducted no later than January 1, 2019 and at least once every three (3) years thereafter. At that time a new flow-weighted average emission factor in terms of: lb PM_{10}/MMBtu shall be derived. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubbers to arrive at a combined daily PM_{10} emission total. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters on all gas-fueled combustion equipment.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply fuel oil to combustion sources.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Results shall be tabulated for each day, and records shall be kept which include all meter readings (in the appropriate units), and the calculated emissions.

ii. Source-wide NO_x Cap

By no later than January 1, 2019, NO_x emissions into the atmosphere from all emission points shall not exceed 2.09 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.g.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:
Low NO_x burners (LNB): 41 lbs/MMscf
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu
Selective catalytic reduction (SCR): 0.02 lbs/MMbtu
All other combustion burners: 100 lb/MMscf

Where:
"Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner.

All fuel oil combustion: 120 lbs/Kgal

B. The default emission factors listed in IX.H.2.f.ii.A above apply until such time as stack testing is conducted as outlined in IX.H.1.e or by NSPS.

C. Compliance with the Source-wide NO_x Cap shall be determined for each day as follows:

Total daily NO_x emissions for emission points shall be calculated by adding the results of the NO_x equations for plant gas, fuel oil, and natural gas combustion listed below. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating (BTU/hr) * 24 hours per day /(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Results shall be tabulated for each day; and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions.

iii. Source-wide SO_2 Cap
By no later than January 1, 2019, the emission of SO_2 from all emission points shall not exceed 0.31 tons per day (tpd).

A. Setting of emission factors:
The emission factors listed below shall be applied to the relevant quantities of fuel combusted:

Natural gas - 0.60 lb SO_2/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H2S content of the fuel gas. The CEM shall operate as outlined in IX.H.1.f.

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:

(lb of SO_2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO_2/32 g S)

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted.

B. Compliance with the Source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding daily results of the SO_2 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

The equations used to determine emissions are:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs)/(2,000 lb/ton)

For purposes of these equations, fuel consumption shall be measured as outlined below:

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H2S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

g. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

A. Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed 30,000 miles.

KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System or equivalent. The system shall use real time tracking to determine daily mileage.

B. KUC shall use ultra-low sulfur diesel fuel in its haul trucks.

C. To minimize emissions at the mine, the owner/operator shall:

I. Control emissions from the in-pit crusher with a baghouse.

II. Use ore conveyors as the primary means for transport of crushed ore from the mine to the concentrator.

D. To minimize fugitive dust on roads at the mine, the owner/operator shall perform the following measures:

I. Apply water to all active haul roads as weather and operational conditions warrant except during precipitation or freezing weather conditions, and shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.

II. Chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing weather conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.

E. KUC is subject to the requirements in the most recent federally approved Fugitive Emissions and Fugitive Dust rules.

ii. Copperton Concentrator (CC)

A. Control emissions from the Product Molybdenite Dryers with a scrubber during operation of the dryers.

During operation of the dryers, the static pressure differential between the inlet and outlet of the scrubber shall be within the manufacturer's recommended range and shall be recorded weekly.

The manometer or the differential pressure gauge shall be calibrated according to the manufacturer's instructions at least once per year.

h. Kennecott Utah Copper (KUC): Power Plant and Tailings Impoundment

i. Utah Power Plant

A. Boilers #1, #2, and #3 shall cease operations permanently upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine).

B. Unit #5 shall not exceed the following emission rates to the atmosphere:

Pollutant	lb/hr	lb/event	ppmdv ($15\%\ O_2$ dry)
I. PM_{10} with duct firing: Filterable + condensable	18.8		
II. NO_x:			2.0
Startup/shutdown		395	

III. Startup / Shutdown Limitations:

1. The total number of startups and shutdowns together shall not exceed 690 per calendar year.

2. The NO_x emissions shall not exceed 395 lbs from each startup/shutdown event, which shall be determined using manufacturer data.

3. Definitions:

(i) Startup cycle duration ends when the unit achieves half of the design electrical generation capacity.

(ii) Shutdown duration cycle begins with the initiation of turbine shutdown sequence and ends when fuel flow to the gas turbine is discontinued.

C. Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.2.h.i.B shall be performed as follows for the following air contaminants

* Initial compliance testing for the natural gas turbine and duct burner is required. The initial test date shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

The limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

Pollutant	Test Frequency
I. PM_{10}	every year
II. NO_x	every year

D. The following requirements are applicable to Units #1, #2, #3, and #4 during the period November 1 to February 28/29 inclusive:

I. During the period from November 1, to the last day in February inclusive, only natural gas shall only be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. The Director shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.

II. When burning natural gas the emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Pollutant 68°F, 29.92 in. Hg	grains/dscf	ppmdv (3% O_2)
1. PM_{10} Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NOx: Units #1, #2 and #3 (each)		336
3. NO_x Unit #4		336
(Unit 4 after January 1, 2018)		60

III. When using coal as a fuel during a curtailment of the natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Pollutant 68°F, 29.92 in Hg	grains/dscf	ppmdv (3% O_2)
1. Units #1, #2 and #3 (i) PM_{10}		
filterable	0.029	
filterable + condensable	0.29	
(ii) NO_x Units 1, 2 & 3		426.5
2. Unit #4 (i) PM_{10}		
filterable	0.029	
filterable +		

condensable	0.29	
(ii) NO_x		384

IV. If the units operated during the months specified above, stack testing to show compliance with the emission limitations in H.2.h.i.D.II and III shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency	Initial Test
1. PM_{10}	every year	#
2. NO_x	every year	#

Initial compliance testing is required for Unit #4 after low NO_x burner installation. The initial test date shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

The limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

E. The following requirements are applicable to Units #1, #2, #3, and #4 during the period March 1 to October 1 inclusive:

I. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Pollutant 68°F, 29.92 in Hg	grains/dscf	ppmdv (3% O_2)
1. Units #1, #2, and #3		
(i) PM_{10} filterable	0.029	
(ii) filterable + condensable	0.29	
(iii) NO_x Units #1, #2, and #3		426.5
2. Unit #4		
(i) PM_{10} filterable	0.029	
(ii) NO_x		384

II. If the units operated during the months specified above, stack testing to show compliance with the emission limitations in H.2.h.i.E.I shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency
1. PM_{10}	every year
2. NO_x	every year

The limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

F. The sulfur content of any fuel burned shall not exceed 0.66 lb of sulfur per million BTU per test.

I. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or C and systematic spacing.

II. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D methods 2013, 3177, 3173, and 2015.

III. KUC shall measure at least 95% of the required increments in any one month that coal is burned in Units #1, #2, #3 or #4.

ii. Tailings Impoundment

A. No more than 50 contiguous acres or more than 5% of the total tailings area shall be permitted to have the potential for wind erosion.

I. Wind erosion potential is the area that is not wet, frozen, vegetated, crusted, or treated and has the potential for wind erosion.

II. KUC shall conduct wind erosion potential grid inspections monthly between February 15 and November 15. The results of the inspections shall be used to determine wind erosion potential.

III. If KUC or the Director of Utah Division of Air Quality (Director) determines that the percentage of wind erosion potential is exceeded, KUC shall meet with the Director, to discuss additional or modified fugitive dust controls/operational practices, and an implementation schedule for such, within five working days following verbal notification by either party.

B. If between February 15 and November 15 KUC's daily weather forecast using surrounding area meteorological data is for a wind event (a wind event is defined as wind gusts exceeding 25 mph for more than one hour) the procedures listed below shall be followed within 48 hours of issuance of the forecast. KUC shall:

I. Alert the Utah Division of Air Quality promptly.

II. Continue surveillance and coordination of appropriate measures.

C. KUC is subject to the requirements of the most recent federally approved Fugitive Emissions and Fugitive Dust rules.

Kennecott Utah Copper (KUC): Smelter & Refinery

i. Smelter

A Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

I. Main Stack (Stack No. 11)

1. PM_{10}
   a. 89.5 lbs/hr (filterable)
   b. 439 lbs/hr (filterable + condensable)

2. SO_2
   a. 552 lbs/hr (3 hr. rolling average)
   b. 422 lbs/hr (daily average)

3. NO_x
   a. 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
   a. 14.0 lbs/hr (calendar -day average)

B. Stack testing to show compliance with the emissions limitations of Condition (A) above shall be performed as specified below:

Emission Point	Pollutant	Test Frequency
I. Main Stack (Stack No. 11)	PM_{10}	every year
	SO_2	CEM
	NO_x	CEM
II. Holman Boiler	NO_x	every three years & alternate method according to applicable NSPS standards

C. KUC must operate and maintain the air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

ii. Refinery:

A. Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission Rate
The sum of two (Tankhouse) Boilers	NO_x	9.5 lbs/hr
Combined Heat Plant	NO_x	5.96 lbs/hr

B. Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Testing Frequency
Tankhouse Boilers	NO_x	every three years*
Combined Heat Plant	NO_x	every year

*Stack testing shall be performed on boilers that have operated at least 300 hours during a three year period.

C. KUC must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

iii. Molybdenum Autoclave Project (MAP):

A. Emissions to the atmosphere from the Natural Gas Turbine combined with Duct Burner and with Turbine Electric Generator (TEG) Firing shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission Rate
Combined Heat Plant	NO_x	5.01 lbs/hr

B. Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Testing Frequency
Combined Heat Plant	NO_x	every year

To determine mass emission rates (lbs/hr, etc.), the pollutant concentration as determined by the appropriate methods above, shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.

C. Standard operating procedures shall be followed during startup and shutdown operations to minimize emissions.

j. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

A. Emissions of NO_x shall be no greater than 179 lbs/hr on a three (3) hour block average basis.

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.1.f.

ii. Steam Generating Unit #2:

A. Emissions of NO_x shall be no greater than 204 lbs/hr on a three (3) hour block average basis.

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O2 monitors to determine compliance with the NO_x limitation.

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

I. 142 lbs/hr on a three (3) hour block average basis, applicable between November 1 and February 28/29

II. 203 lbs/hr on a three (3) hour block average basis, applicable between March 1 and October 31

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.1.f.

iv. Steam Generating Units #1-3:

A. The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel oil or better as back-up fuel in the boilers. The No. 2 fuel oil may be used only during periods of natural gas curtailment and for maintenance firings. Maintenance firings shall not exceed one-percent of the annual plant Btu requirement. In addition, maintenance firings shall be scheduled between April 1 and November 30 of any calendar year. Records of fuel oil use shall be kept and they shall show the date the fuel oil was fired, the duration in hours the fuel oil was fired, the amount of fuel oil consumed during each curtailment, and the reason for each firing.

v. Natural Gas-fired Simple Cycle Turbine Units:

A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.1.f.

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when the fuel values open and natural gas is supplied to the combustion turbines

B. Startup ends when either of the following conditions is met:
   I. The NO_x water injection pump is operational, the dilution air temperature is greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia block value has opened and ammonia is being injected into the SCR and the unit has reached an output of ten (10) gross MW; or

   II. The unit has been in startup for two (2) hours.

C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross MW with the intent of removing the unit from service.

D. Shutdown ends at the cessation of fuel input to the turbine combustor.

E. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.

F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with an electrical meter.

k. Tesoro Refining & Marketing Company

i. Source-wide PM_{10} Cap
By no later than January 1, 2019, combined emissions of PM_{10} shall not exceed 2.25 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.k.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Plant gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Fuel Oil: The PM_{10} emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42

FCC Wet Scrubber:
The PM_{10} emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.

B. The default emission factors listed in IX.H.2.k.i.A above apply until such time as stack testing is conducted as outlined below:

Initial PM_{10} stack testing on the FCC wet gas scrubber stack shall be conducted no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the Source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubber to arrive at a combined daily PM_{10} emission total. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

The equation used to determine emissions for the boilers and furnaces shall be as follows:

Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x Cap
By no later than January 1, 2019, combined emissions of NO_x shall not exceed 1.988 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed in IX.H.2.k.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:
Low NO_x burners (LNB): 41 lbs/MMbtu
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Diesel fuel: shall be determined from the latest edition of AP-42

B. The default emission factors listed in IX.H.2.k.ii.A above apply until such time as stack testing is conducted as outlined below:

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least once every three (3) years following the date of the last test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.k.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide NO_x Cap shall be determined for each day as follows:

Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results.

A NO_x CEM shall be used to calculate daily NOx emissions from the FCCU wet gas scrubber stack. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the flow rate of the flue gas. The NO_x concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO_2 Cap
By no later than January 1, 2019, combined emissions of SO_2 shall not exceed 3.1 tons per day (tpd).

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Diesel fuel: shall be determined from the latest edition of AP-42

Plant fuel gas: the emission factor shall be calculated from the H2S measurement or from the SO_2 measurement obtained by direct testing/monitoring.

Where mixtures of fuel are used in a unit, the above factors shall be weighted according to the use of each fuel.

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas, plant fuel gas, and propane combustion to those from the wet gas scrubber stack.

Daily SO_2 emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO_2 concentration in the flue gas by the flow rate of the flue gas. The SO2 concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

Daily SO_2 emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily at each affected unit by the appropriate emission factor.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H2S (averaged for each one-hour period), all meter reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

l. University of Utah: University of Utah Facilities

i. Emissions to the atmosphere from the listed emission points in Building 303 shall not exceed the following concentrations:

Emission Point	Pollutant	ppmdv (3% O2 dry)
A. Boiler #3	NO_x	187
B. Boilers #4a & #4b	NO_x	9
C. Boilers #5a & #5b	NO_x	9
D. Turbine	NO_x	9
E. Turbine and WHRU Duct burner	NO_x	15

*Boiler #4 will be replaced with Boiler #4a and #4b by 2018.

ii. Testing to show compliance with the emissions limitations of Condition i above shall be performed as specified below:

Emission Point	Pollutant	Initial Test	Test Frequency
A. Boiler #3	NO_x	*	every year#
B. Boilers #4a & 4b	NO_x	2018	every year#
C. Boilers #5a & 5b	NO_x	2017	every year#
D. Turbine	NO_x	*	every year#
E. Turbine and WHRU Duct burner	NO_x	*	every year#

* Initial tests have been performed and the next method test using EPA approved test methods shall be performed within 3 years of the last stack test.

A compliance test shall be performed at least once every three years from the date of the last compliance test that demonstrated compliance with the emission limit(s). Compliance testing shall be performed using EPA approved test methods acceptable to the Director. The Director shall be notified, in accordance with all applicable rules, of any compliance test that is to be performed. Beginning January 2018, annual screening with a portable monitor must be conducted in those years that a compliance test is not performed. Screening with a portable monitor shall be performed in accordance with the

portable monitor manufacturer's specifications. If screening with a portable monitor indicates a potential exceedance of the concentration limit, a compliance test must be performed within 90 days of that screening. Records shall be kept on site which indicate the date, time, and results of each screening and demonstrate that the potable monitor was operated in accordance with manufacturer's specifications. .

iii. After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler and shall not exceed 300 hours of operation per rolling-12 months. Boiler #3 may be operated on a continuous basis if it is equipped with low NO_x burners or is replaced with a boiler that has low NO_x burners.

m. West Valley Power Holdings, LLC.: West Valley Power Plant.

i. Total emissions of NO_x from all five (5) turbines combined shall be no greater than 1050 lb of NO_x on a daily basis. For purposes of this subpart, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

ii. Total emissions of NO_x from all five (5) turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.

iii. The NO_x emission rate (lb/hr) shall be determined by CEM. The CEM shall operate as outlined in IX.H.1.f.

H.3 Source Specific Emission Limitations in Utah County PM_{10} Nonattainment/Maintenance Area

a. Brigham Young University: Main Campus

i All central heating plant units shall operate on natural gas from November 1 to February 28 each season beginning in the winter season of 2013-2014. Fuel oil may be used as backup fuel during periods of natural gas curtailment. The sulfur content of the fuel oil shall not exceed 0.0015 % by weight. BYU must maintain a fuel specification certification document from the fuel supplier with the sulfur content guarantee. Alternatively, sulfur content may be verified through testing completed by BYU or the fuel supplier using ASTM Method D-4294-10 or EPA approved equivalent acceptable to the Director.

ii. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Emission Point	Pollutant	ppm (7% O_2 dry)*		lb/hr	
A. Unit #1	NO_x	95	36	9.55	5.44
B. Unit #4	NO_x	127	36	38.5	19.2
C. Unit #6	NO_x	127	36	38.5	19.2

* Unit #1 NO_x limit is 95 ppm (9.55 lb/hr) until it operates for more than 300 hours during a rolling 12-month period, then the limit will be 36 ppm (5.44 lb/hr). The NO_x limit for units #4 and #6 is 127 ppm (38.5 lb/hr) and starting on December 31, 2018, the limit will then be 36 ppm (19.2 lb/hr).

Emission Point	Pollutant	ppm (7% O_2 dry)	lb/hr
D. Unit #2	NO_x	331	37.4
	SO_2	597	56.0
E. Unit #3	NO_x	331	37.4
	SO_2	597	56.0
F. Unit #5	NO_x	331	74.8
	SO_2	597	112.07

iii. Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Initial test	Test Frequency
A. Unit #1	NO_x	&	every year*
B. Unit #2	NO_x	#	every year*
C. Unit #3	NO_x	#	every year*
D. Unit #4	NO_x	#	every year*
E. Unit #5	NO_x	#	every year*
F. Unit #6	NO_x	#	every year*

Stack tests shall be performed in accordance with IX.H.1.e.

& If Unit #1 is operated for more than 100 hours per rolling 12-month period, the stack test shall be performed within 60 days of exceeding 100 hours of operations. Unit #1 shall only be operated as a back-up boiler to Units #4 and #6 and shall not be operated more than 300 hours per rolling 12-month period. If Unit #1 operates more than 300 hours per rolling 12-month period, then low NO_x burners with Flue Gas Recirculation shall be installed and tested within 18 months of exceeding 300 hours of operation and the maximum NO_x concentration shall be 36 ppm.

The test shall be performed at least every 3 years based on the date of the last stack test. Units #4 and #6 shall be retested by March 1, 2018.

* A compliance test shall be performed at least once every three years from the date of the last compliance test that demonstrated compliance with the emission limit(s). Compliance testing shall be performed using EPA approved test methods acceptable to the Director. The Director shall be notified, in accordance with all applicable rules, of any compliance test that is to be performed. Beginning January 2018, annual screening with a portable monitor must be conducted in those years that a compliance test is not performed. Screening with a portable monitor shall be performed in accordance with the portable monitor manufacturer's specifications. If screening with a portable monitor indicates a potential exceedance of the concentration limit, a compliance test must be performed within 90 days of that screening. Records shall be kept on site which indicate the date, time, and results of each screening and demonstrate that the potable monitor was operated in accordance with manufacturer's specifications.

iv. Central Heating Plant Coal-Fired Boilers

A. Startup and shutdown events shall not exceed 216 hours per boiler per 12-month rolling period.

B. The sulfur content of any coal or any mixture of coals burned shall not exceed either of the following:

I. 0.54 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4239-85, or EPA-approved equivalent acceptable to the Director.

II. 0.60% by weight as determined by ASTM Method D-4239-85, or EPA-approved equivalent acceptable to the Director.

For the sulfur content of coal, Brigham Young University shall either:

III. Determine the weight percent sulfur and the fuel heating value by submitting a coal sample to a laboratory, acceptable to the Director, on no less than a monthly basis; or

IV. For each delivery of coal, inspect the fuel sulfur content expressed as weight % determined by the vendor using methods of the ASTM; or

V. For each delivery of coal, inspect documentation provided by the vendor that indirectly demonstrates compliance with this provision.

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM_{10} emissions (filterable and condensable) shall not exceed 0.236 ton/day
$PM_{2.5}$ emissions (filterable and condensable) shall not exceed 0.196 ton/day

A day is defined as from midnight to the following midnight.

ii. Testing

A. Stack testing shall be performed as specified below:

I. Frequency: Emissions shall be tested every three years. The test shall be performed as soon as possible and in no case later than December 31, 2017.

B. The daily limit shall be calculated by multiplying the most recent stack test results by the appropriate hours of operation for each day.

iii. Montecatini Plant:

NO_x emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NO_x emissions shall not exceed 18.4 lb/hr

v. Testing

A. Stack testing for NO_x shall be performed as specified below:

I. Stack testing to show compliance with the NOx emission limitations shall be performed as specified below:

1. Testing and Frequency. Emissions shall be tested every three years using an EPA approved test method.

II. NO_x concentration (ppmdv) shall be used as an indicator to provide a reasonable assurance of compliance with the NO_x emission limitation as specified below:

1. Measurement Approach: NO_x concentration (ppmdv) shall be determined by using a continuous NO_x monitoring system.

2. Performance Criteria:
   i. QA/QC Practices and Criteria: The continuous monitoring system shall be operated, calibrated, and maintained in accordance with manufacture's recommendations. Zero and span drift tests shall be conducted on a daily

basis.

III. The EPA approved method test for the Montecatini Plant shall be performed as soon as possible and in no case later than December 31, 2017, and the test for the Weatherly Plant shall be performed as soon as possible and in no case later than December 31, 2018.

vi. Start-up/Shut-down

A. Startup / Shutdown Limitations:

I. Planned shut-down and start-up events shall not exceed 50 hours per acid plant (Montecatini or Weatherly) per 12-month rolling period.

II. Total startup and shutdown events shall not exceed four hours per acid plant in any one calendar day.

c. PacifiCorp Energy: Lake Side Power Plant

i. Block #1 Turbine/HRSG Stacks:

A. Emissions of NO_x shall not exceed 14.9 lb/hr on a 3-hr average basis

B. Compliance with the above conditions shall be demonstrated as follows:

I. NO_x monitoring shall be through use of a CEM as outlined in IX.H.1.f

ii. Block #2 Turbine/HRSG Stacks:

A. Emissions of NO_x shall not exceed 18.1 lb/hr on a 3-hr average basis

B. Compliance with the above conditions shall be demonstrated as follows:

I. NO_x monitoring shall be through use of a CEM as outlined in IX.H.1.f

iii. Startup / Shutdown Limitations:

A. Block #1:

I. Startup and shutdown events shall not exceed 613.5 hours per turbine per 12-month rolling period.

II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NO_x emissions from the Block #1 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O_2.

B. Block #2:

I. Startup and shutdown events shall not exceed 553.6 hours per turbine per 12-month rolling period.

II. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NO_x emissions from the Block #2 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O_2.

C. Definitions:

I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr emission limits listed in IX.H.3.c.i and ii above.

II. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine.

III. Transient load conditions are those periods, not to exceed four consecutive 15-minute periods, when the 15-minute average NO_x concentration exceeds 2.0 ppmv dry @ 15% O_2. Transient load conditions consist of the following:

1. Initiation/shutdown of combustion turbine inlet air-cooling.

2. Rapid combustion turbine load changes.

3. Initiation/shutdown of HRSG duct burners.

4. Provision of Ancillary Services and Automatic Generation Control.

IV. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

e. Payson City Corporation: Payson City Power

i. Emissions of NO_x shall be no greater than 1.54 ton per day for all engines combined.

ii. Compliance with the emission limitation shall be determined by summing the emissions from all the engines. Emission from each engine shall be calculated from the following equation:

Emissions (tons/day) = (Power production in kW-hrs/day) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)

A. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested at least every three years from the previous test.

B. NO_x emissions shall be calculated on a daily basis.

C. A day is equivalent to the time period from midnight to the following midnight.

D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

f. Provo City Power: Power Plant

i. NO_x emissions from the operation of all engines at the plant shall not exceed 2.45 tons per day.

ii. Compliance with the emission limitation shall be determined by summing the emissions from all the engines. Emission from each engine shall be calculated from the following equation:

Emissions (tons/day) = (Power production in kW-hrs/day) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)

A. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested every 8,760 hours of operation or at least every three years from the previous test, whichever occurs first.

B. NO_x emissions shall be calculated on a daily basis.

C. A day is equivalent to the time period from midnight to the following midnight.

D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

g. Springville City Corporation: Whitehead Power Plant

i. NO_x emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day.

ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM. CEM will be performed in accordance with IX.H.1.f. A day is equivalent to the time period from midnight to the following midnight. Emissions shall be calculated for NO_x for each individual engine by the following equation:

$$D = (X * K)/453.6$$

Where:
X = grams/kW-hr rate for each generator (recorded by CEM)
K = total kW-hr generated by the generator each day (recorded by output meter)
D = daily output of pollutant in lbs/day

H.4 Interim Emission Limits and Operating Practices

a. The terms and conditions of this Subsection IX.H.4 shall apply to the sources listed in this section on a temporary basis, as a bridge between the 1991 PM_{10} State Implementation Plan and this PM_{10} Maintenance Plan. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM_{10} Maintenance Plan. These bridge requirements are needed to impose limits on the sources that have time delays for implementation of controls. During this timeframe, the sources listed in this section may not meet the established limits listed in IX.H.1 and IX.H.2. As the control technology for the sources listed in this section is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 become applicable and those limits replace the limits in this subsection. In no case, shall the terms and conditions listed in this Subsection IX.H.4 extend beyond January 1, 2019.

b. Petroleum Refineries:

i. All petroleum refineries in or affecting the PM_{10} nonattainment/maintenance area shall, for the purpose of this PM_{10} Maintenance Plan:

A. Achieve an emission rate equivalent to no more than 9.8 kg of SO_2 per 1,000 kg of coke burn- off from any Catalytic Cracking unit by use of low-SO_x catalyst or equivalent emission reduction techniques or procedures, including those outlined in 40 CFR 60, Subpart J. Unless otherwise specified in IX.H.2, compliance shall be determined for each day based on a rolling seven-day average.

B. Compliance Demonstrations.

I. Compliance with the maximum daily (24-hr) plant-wide emission limitations for PM_{10}, SO_2, and NO_x shall be determined by adding the calculated emission estimates for all fuel burning process equipment to those from any stack-tested or CEM-measured source components. NO_x and PM_{10} emission factors shall be determined from AP-42 or from test data.

For SO_x, the emission factors are:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Plant gas: the emission factor shall be calculated from the H_2S measurement required in IX.H.1.g.ii.A.

Fuel oils (when permitted): The emission factor shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S)

Where mixtures of fuel are used in an affected unit, the above factors shall be weighted according to the use of each fuel.

II. Daily emission estimates for stack-tested source components shall be made by multiplying the latest stack-tested hourly emission rate times the logged hours of operation (or other relevant parameter) for that source component for each day. This shall not preclude a source from determining emissions through the use of a CEM that meets the requirements of R307-170.

c. Big West Oil Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all external combustion process equipment shall not exceed the following:

I. 0.377 tons per day, between October 1 and March 31;
II. 0.407 tons per day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

The daily primary PM_{10} contribution from the Catalyst Regeneration System shall be calculated using the following equation:

Emitted PM_{10} = (Feed rate to FCC in kbbl/time) * (22 lbs/kbbl)

wherein the emission factor (22 lbs/kbbl) may be re-established by stack testing. Total 24-hour PM_{10} emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the estimate for the Catalyst Regeneration System.

ii. SO_2 Emissions

A. Combined emissions of sulfur dioxide from all external combustion process equipment shall not exceed the following:

I. 2.764 tons/day, between October 1 and March 31;
II. 3.639 tons/day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

The daily SO_2 emission from the Catalyst Regeneration System shall be calculated using the following equation:

SO_2 = [43.3 lb SO_2/hr / 7,688 bbl feed/day] x [(operational feed rate in bbl/day) x (wt% sulfur in feed / 0.1878 wt%) x (operating hr/day)]

The FCC feed weight percent sulfur concentration shall be determined by the refinery laboratory every 30 days with one or more analyses. Alternatively, SO_2 emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

Emissions from the SRU Tail Gas Incinerator (TGI) shall be determined for each day by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas.

Total 24-hour SO_2 emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the values for the Catalyst Regeneration System and the SRU.

iii. NO_x Emissions

A. Combined emissions of NO_x from all external combustion process equipment shall not exceed the following:

I. 1.027 tons per day, between October 1 and March 31;
II. 1.145 tons per day, between April 1 and September 30.

B. Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

The daily NO_x emission from the Catalyst Regeneration System shall be calculated using the following equation:

NO_x = (Flue Gas, moles/hr) x (180 ppm /1,000,000) x (30.006 lb/mole) x (operating hr/day)

wherein the scalar value (180 ppm) may be re-established by stack testing.

Alternatively, NO_x emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

Total 24-hour NO_x emissions shall be calculated by adding the daily emissions from gas-fired compressor drivers and the external combustion process equipment to the value for the Catalyst Regeneration System.

d. Chevron Products Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all external combustion process equipment shall be no greater than 0.234 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO_2 Emissions

A. Combined emissions of sulfur dioxide from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shall not exceed 0.5 tons/day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Alternatively, SO_2 emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO_x Emissions

A. Combined emissions of NO_x from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator and the SRU Tail Gas Incinerator, shall be no greater than 2.52 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Alternatively, NO_x emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iv. Chevron shall be permitted to combust HF alkylation polymer oil in its Alkylation unit.

e. Holly Refining and Marketing Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all combustion sources, shall be no greater than 0.44 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B, or from testing as described below, by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO_2 Emissions

A. Combined emissions of SO_2 from all sources shall be no greater than 4.714 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from sectionIX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Emissions from the FCC wet scrubbers shall be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO_x Emissions:

A. Combined emissions of NO_x from all sources shall be no greater than 2.20 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

f. Tesoro Refining & Marketing Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall be no greater than 0.261 tons per day.

Emissions for gas-fired compressor drivers and the group of external combustion process equipment shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

ii. SO_2 Emissions

A. Combined emissions of SO_2 from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall not exceed the following:

I. November 1 through end of February: 3.699 tons/day
II. March 1 through October 31: 4.374 tons/day

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

Emissions from the ESP stack (FCC/CO Boiler) shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas.

The SO_2 concentration in the flue gas shall be determined by a continuous emission monitor (CEM).

iii. NO_x Emissions

A. Combined emissions of NO_x from gas-fired compressor drivers and all external combustion process equipment shall be no greater than 1.988 tons per day.

Emissions shall be determined for each day by multiplying the appropriate emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing the results for the group of affected units.

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