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DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A.Q. PROGRAM

DYNAMIS
ENERGY™

October 12, 2012

Dynamis Energy, LLC
776 E. Riverside Drive, Suite 150
Eagle, ID 83616

Mr. Morrie Lewis, Permit Writer
Department of Environmental Quality
Air Quality Division
1410 North Hilton
Boise, Idaho 83706-1255

Re: Facility ID No. 001-00252, Dynamis Energy, LLC, Boise
Permit to Construct Application, Request for Additional Information for a Waste-to-Energy Project at Hidden Hollow Landfill

Dear Mr. Lewis:

On April 25, 2012, Dynamis submitted to the Department of Environmental Quality a permit to construct (PTC) application from Dynamis Energy, LLC for the for a waste-to-energy project to be located at Hidden Hollow Landfill in Ada County. Subsequent to this date, supplemental information and documents were submitted to DEQ, sometimes without certification by a responsible official. On October 10, 2012, Dynamis received a letter via email from you requesting the documents identified below be reviewed and resubmitted in order to be included in the PTC application.

a) Signed lease agreement(s) that specify the leased boundary coordinates and provide authority for controlling access to the ambient air boundary used in the preconstruction modeling compliance demonstrations. (The lease agreement submitted in May 2012 does not match the boundary used in the most recent modeling analyses.) If it is not identified within the lease agreements, a description of the method the permittee will use to control public access into the ambient air boundary (e.g., perimeter fencing) should also be provided.

b) Copies of the original source test data relied upon to establish emission factors and estimate emissions for the Thermal Conversion Unit.

c) Documentation of Dynamis Energy source test information and emission factor calculations (spreadsheet).
email "Dynamis Emissions Factors Development," received 5/24/12 (8:38 am)

d) Response to Permit to Construct Application Incompleteness, received June 11, 2012.

e) Documentation of the proposed daily tire throughput limitation.
email "Dynamis Facility Permit - Tires," received 7/2/12 (10:06 am)

f) Documentation of receptor elevations, ambient air boundary, and source locations.
email "Dynamis Energy Modeling," received 7/9/12 (12:08 pm)

g) Documentation of the NOx control efficiency guarantee for the selective non-catalytic reduction (SNCR) system.
email "Dynamis SNCR System," received 7/26/12 (12:16 pm)

h) Revised Air Dispersion Modeling report, including electronic copies of the appended spreadsheet and modeling files.
email "Dynamis WTE Facility Revised Modeling," received 7/30/12 (11:16 am)

i) Documentation of discussion concerning NSPS Subpart Eb compliance options.
email "Re: CEMS," received 7/31/12 (5:55 pm)

j) Documentation of the ammonia slip control efficiency guarantee for the caustic scrubber (most recent revision "D").
email "RE: Ammonia Slip," received 8/7/12 (12:43 pm), and updated rev. D attachment

k) Documentation of various items, including cooling tower emissions (spreadsheet), scrubber operating parameters (spreadsheet), and SNCR urea injection flow rate.
email "RE: Permit Conditions Items," received 8/16/12 (4:59 pm)

l) Documentation of various items, including ammonia slip emissions, NO2/NOx ratios, and revised SIL cumulative impact analyses.
email "FW: DEQ questions regarding latest modeling submittals," received 8/27/12 (8:30am)

m) Dimensional drawing depicting the revised lease area used in preconstruction modeling compliance demonstrations.
email "RE: DEQ questions regarding latest modeling submittals," received 8/28/12 (4:32 pm)

n) Documentation of various items, including annual emergency generator emissions estimates, and ambient air quality modeling results.
email "RE: DEQ questions regarding annual modeling," received 9/10/12 (9:35 pm)

Item *'a'* listed above requests that a description of the method the permittee will use to control public access into the ambient air boundary (e.g., perimeter fencing) be provided. This description has previously been provided in the modeling report, under Section 5.0 – Receptor Network. Dynamis will control access to the leased property (which now includes the control area easement) through posting of signage and by training facility personnel to patrol and prevent public access. Access to the area south of the facility is also limited by terrain. In addition, Dynamis will ensure that Ada County Landfill employees understand that the facility is leased property of Dynamis, and access is restricted to anyone other than Dynamis personnel or invited guests.

In addition to the items listed above, Dynamis is submitting revised emission factor calculations for dioxins and furans. The emission factor and associated emission rates were updated in the emissions inventories submitted to DEQ, however, the actual emission factor development spreadsheets were not submitted to DEQ. The attached pdfs should replace pages 1, 2, 3 and 11 of item *'c'* identified above and included with the DEQ letter as pages 5, 6, 7 and 15 of the pdf.

Several of the items listed above were submitted by JBR Environmental Consultants, Inc. (JBR) on behalf of Dynamis. A certification statement from JBR is also included with this letter.

It should be noted that several of the items included with this letter were accurate at the time of submittal, however, due to project updates, some of the items now contain outdated information, specifically in regards to emissions inventory refinement and property boundary expansion.

Pursuant to IDAPA 58.01.01.123, I hereby certify that, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Please feel free to contact us or JBR if you have any questions or need additional information.

Sincerely,

C. Lloyd Mahaffey
Chairman & CEO, Dynamis Energy, LLC

Enclosures

Cc: JBR Environmental Consultants, Inc.

Dynamis Energy, LLC
776 E Riverside Dr. Ste 150
Eagle, Idaho 83616
208-938-2680 (p)

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DEPARTMENT OF ENVIRONMENTAL QUALITY
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JBR
creating solutions for today's environment

October 11, 2012

Mr. Wade Thomas, SVP and General Counsel
Mr. Lloyd Mahaffey, Chairman and CEO
Dynamis Energy, LLC
776 E Riverside Drive. Suite 150
Eagle, ID 83616

Re: Dynamis Energy, LLC, Ada County Waste-To-Energy Facility
Truth, Accuracy and Completeness Certification

The purpose of this letter is to certify that all information provided to the Idaho Department of Environmental Quality (IDEQ) by JBR Environmental Consultants, Inc. (JBR) on behalf of Dynamis, in support of the Permit to Construct application for a Waste-to-Energy Facility at the Ada County Landfill, is true accurate and complete. The above referenced information includes but is not limited to, the permit application itself and items identified in the October 10, 2012 letter from Mr. Morrie Lewis.

In accordance with IDAPA 58.01.01.123, I certify based on information and belief formed after reasonable inquiry, the statements and information referenced in this letter is true, accurate, and complete.

Sincerely,

S. Manoulian

Shannon Manoulian, P.E.

JBR Environmental Consultants, Inc.
7669 W. Riverside Dr., Ste. 101
Boise, Idaho 83714
[p] 208.853.0883
[f] 208.853.0884
www.jbrenv.com

Source Test References

Test Reference Number	Report Title	Author(s)	Additional Information	Data Included in Tests
1A	April - May 1993 Entech, Inc. Model TOS-80 Emissions Monitoring in Anchorage, Alaska. June 1993. For: NATCHIQ, Anchorage, Alaska	John Nordin, Steve Lindblom	Burn 1: 4/20/1993, 18 yd^3 MSW	CO2, NOx, FH PM, BH PM, HCl, Metals, Dioxin/Furan, Ash
1B	April - May 1993 Entech, Inc. Model TOS-80 Emissions Monitoring in Anchorage, Alaska. June 1993. For: NATCHIQ, Anchorage, Alaska	John Nordin, Steve Lindblom	Burn 2: 4/22/1993, 16.5 yd3 MSW, 4 yd3 tires, oil waste	CO2, NOx, FH PM, BH PM, HCl, Metals, Dioxin/Furan, Ash
1C	April - May 1993 Entech, Inc. Model TOS-80 Emissions Monitoring in Anchorage, Alaska. June 1993. For: NATCHIQ, Anchorage, Alaska	John Nordin, Steve Lindblom	Burn 4: 4/26/1993, 23 Auto Tires, 2 truck tires, whole	CO2, NOx, FH PM, BH PM, HCl, Metals, Dioxin/Furan, Ash
1D	April - May 1993 Entech, Inc. Model TOS-80 Emissions Monitoring in Anchorage, Alaska. June 1993. For: NATCHIQ, Anchorage, Alaska	John Nordin, Steve Lindblom	Burn 5: 4/28/1993, 18 yd3 MSW, 200 lb wooden pallets	CO2, NOx, FH PM, BH PM, HCl, Metals, Dioxin/Furan, Ash
2	December 1990 Municipal Solid Waste Burn Test in an Entech Thermal Oxidation Demonstation Plant at Western Research Institute. February 1991, revised April 1991. For: Entech, Inc., Anchorage, Alaska	John Nordin, George Huntington	December 3 Burn	CO2, NOx, FH PM, BH PM, HCl, Metals, Dioxin/Furan, SO2, CO, Ash
3	December 1990 Tire Burn Test in an Entech Thermal Oxidation Demonstation Plant at Western Research Institute. February 1991. For: Entech, Inc., Anchorage, Alaska	John Nordin, George Huntington	December 5 and December 7 Burns	CO2, NOx, FH PM, BH PM, HCl, Metals, SO2, CO, Ash
4	September 1991 Tire Burn Test in an Entech Thermal Oxidation Demonstration Plant at Western Research Institute. January 1992. For: Entech, Inc., Anchorage, Alaska.	John Nordin	September 17 Burn	CO2, NOx, SO2, CO

Important Notes:

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average

If all samples are non-detect (less than), average will be zero.

All data available in the source tests listed above was used to develop the emissions factors.

Source Test Result Summary

Test	Summary								
	NOx (ppm)	FH PM (mg/m^3)	BH PM (mg/m^3)	Total PM (mg/m^3)	HCl (ppm)	Dioxins/Furans-TEQ (ng/m^3)	SO2 (ppmv)	CO (ppmv)	CO2 (%)
Test 1A-1C: April-May 1993 Entech Model TOS-80	90	37	21	58	42	2.13E-02	n/a	n/a	10
Test 2: December 1990 MSW Burn Test	33	1.5	<1.157	3	17	n/a	2.6	7.8	6.8
Test 3: December 1990 Tire Burn Test	70	19	9.9	29	7.8	n/a	138	103	11
Test 4: September 1991 Tire Burn Test	105	n/a	n/a	n/a	n/a	n/a	19	22	8.6
Average	***75***	***19***	***11***	***30***	***22***	***2.13E-02***	***53***	***44***	***9.0***

Metals	Test 1A-1C: April-May 1993 Entech Model TOS-80 (mg/m^3)	Test 2: December 1990 MSW Burn Test (mg/m^3)	Test 3: December 1990 Tire Burn Test (mg/m^3)	Average (mg/m^3)
Ag	no data	<0.0003	0	0
Al	no data	0.064	0.031	0.048
As	0	<0.004	0	0.000
B	no data	0.012	0.015	0.014
Ba	no data	0.0015	0.001	0.001
Be	0	<0.00008	0	0.000
Bi	no data	<0.004	0.010	0.007
Ca	no data	0.31	0.128	0.219
Cd	0.052	0.0059	0.004	0.021
Co	no data	<0.0003	0.001	0.002
Cr	0.028	0.0003	0.003	0.010
Cu	no data	0.002	0.007	0.004
Fe	no data	0.037	0.043	0.040
K	no data	<2	0	0.000
Li	no data	0.0007	0.001	0.001
Mg	no data	0.029	0.056	0.042
Mn	0.077	0.001	0.030	0.036
Mo	no data	0.005	0.021	0.013
Na	no data	0.25	0.418	0.334
Ni	0.227	<0.0008	0.033	0.089
P	no data	<0.04	0	0.000
Pb	0.326	0.04	0.072	0.146
Sb	0	<0.004	0.01	0.005
Se	no data	<0.004	0.003	0.004
Sr	no data	0.001	0.001	0.001
Th	no data	<0.002	0	0.000
V	no data	<0.0003	0	0.000
Zn	0.651	0.11	1.27	0.678
Hg*	0.049	no data	no data	0.015

Hg - reduced from information (various literature sources) regarding the reduction in incoming waste stream/untreated flue gas mercury content. Conservatively estimate a 70% reduction in mercury content of incoming waste, therefore reduce source test average concentration by 70%.

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Emission Factor Calculation

Pollutant	Source Test Average	AP-42 Conversion Factor	lb/ton Emission Factor
PM (mg/m^3)	29.7	9.85E-03	2.93E-01
NOx (ppm)	74.5	1.89E-02	1.41E+00
SO2 (ppm)	53.1	2.62E-02	1.39E+00
CO (ppm)	44.3	1.15E-02	5.10E-01
HCl (ppm)	22.3	1.50E-02	3.35E-01
CDD/CDF (ug/m^3)	2.13E-05	9.85E-06	2.10E-10
CO2 (ppm)	9.04E+04	1.47E-02	1.33E+03
Metals (ug/m^3):			
Ag	0.00	9.85E-06	0.00E+00
Al	48	9.85E-06	4.70E-04
As	0.00	9.85E-06	0.00E+00
B	14	9.85E-06	1.35E-04
Ba	1.3	9.85E-06	1.23E-05
Be	0.00	9.85E-06	0.00E+00
Bi	7.2	9.85E-06	7.06E-05
Ca	219	9.85E-06	2.16E-03
Cd	21	9.85E-06	2.02E-04
Co	1.8	9.85E-06	1.77E-05
Cr	10	9.85E-06	1.03E-04
Cu	4.4	9.85E-06	4.33E-05
Fe	40	9.85E-06	3.95E-04
K	0.00	9.85E-06	0.00E+00
Li	0.9	9.85E-06	8.03E-06
Mg	42	9.85E-06	4.17E-04
Mn	36	9.85E-06	3.56E-04
Mo	13	9.85E-06	1.30E-04
Na	334	9.85E-06	3.29E-03
Ni	89	9.85E-06	8.81E-04
P	0.00	9.85E-06	0.00E+00
Pb	146	9.85E-06	1.44E-03
Sb	4.7	9.85E-06	4.60E-05
Se	3.5	9.85E-06	3.45E-05
Sr	0.8	9.85E-06	8.21E-06
Th	0.00	9.85E-06	0.00E+00
V	0.00	9.85E-06	0.00E+00
Zn	678	9.85E-06	6.68E-03
Hg	15	9.85E-06	1.45E-04

AP-42 conversion factor from AP-42, Chapter 2.1, Table 2.1-11.

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Ash Analysis

Constituent	Test 1A-1C: April-May 1993 Entech Model TOS-80 (mg/kg)	Test 2: December 1990 MSW Burn Test (mg/kg)	Test 3: December 1990 Tire Burn Test (mg/kg)	Average (mg/kg)
Ag	0.37	<7	0	0.19
Al	no data	86000	37250	61625
As	0.00	<100	0	0.00
B	no data	450	160.5	305
Ba	4.21	890	189.5	361
Be	no data	<2	0	0.00
Bi	no data	<100	0	0.00
Ca	no data	79000	20425	49713
Cd	4.11	<10	13.725	9.3
Co	no data	12	1780	896
Cr	0.27	130	33	54
Cu	no data	330	149	240
Fe	no data	24000	7325	15663
Hg	0.00	na	0	0.00
K	no data	<49,000	0	0.00
Li	no data	39	61	50
Mg	no data	7700	4850	6275
Mn	no data	1000	115	558
Mo	no data	<10	17.05	14
Na	no data	2800	5725	4263
Ni	no data	29	46.5	38
p	no data	1100	2300	1700
Pb	12.33	490	475	326
Sb	no data	<100	0	0.00
Se	0.00	<100	0	0.00
Sr	no data	210	91.25	151
Th	no data	<50	0	0.00
V	no data	36	41.75	39
Zn	no data	3100	287500	145300

Test 1B-1D April-May 1993 Entech Model TOS-80

Table 11. Dioxins/Furans ng/m3, corrected to 7% O2

Burn	B	C	D	Average		Compound	Concentration		Toxicity Equivalency Factor (TEF)		Toxicity Equivalent (TEQ)
Flow rate (m^3)	1.67E+00	1.51E+00	1.29E+00	1.49E+00		Units:	ng/m3				ng/m3
% O2	4.40E+00	7.30E+00	9.00E+00	6.90E+00							
2,3,7,8-TCDD	*2.02E-03*	*1.35E-03*	*4.52E-03*	0.00E+00		2,3,7,8-TCDD	0.00E+00	X	1	=	0.00E+00
1,2,3,7,8-PeCDD	*2.52E-03*	*2.02E-03*	*9.03E-03*	0.00E+00		1,2,3,7,8-PeCDD	0.00E+00	X	0.5	=	0.00E+00
1,2,3,6,7,8-HxCDD	1.01E-02	6.75E-03	1.81E-02	1.16E-02		1,2,3,6,7,8-HxCDD	1.16E-02	X	0.1	=	1.16E-03
1,2,3,4,7,8-HxCDD	*5.04E-03*	*2.36E-03*	*1.36E-02*	0.00E+00		1,2,3,4,7,8-HxCDD	0.00E+00	X	0.1	=	0.00E+00
1,2,3,7,8,9-HxCDD	*2.52E-03*	6.75E-03	*9.03E-03*	6.10E-03		1,2,3,7,8,9-HxCDD	6.10E-03	X	0.1	=	6.10E-04
1,2,3,4,6,7,8-HpCDD	1.36E-01	1.48E-01	3.79E-01	2.21E-01		1,2,3,4,6,7,8-HpCDD	2.21E-01	X	0.01	=	2.21E-03
OCDD	6.56E-01	8.77E-01	1.36E+00	9.63E-01		OCDD	9.63E-01	X	0.001	=	9.63E-04
									CDD Subtotal	=	4.95E-03
2,3,7,8-TCDF	1.01E-02	4.05E-02	9.03E-03	1.99E-02		2,3,7,8-TCDF	1.99E-02	X	0.1	=	1.99E-03
1,2,3,7,8-PeCDF	*1.77E-03*	5.40E-03	*4.52E-03*	3.89E-03		1,2,3,7,8-PeCDF	3.89E-03	X	0.05	=	1.95E-04
2,3,4,7,8-PeCDF	*1.77E-03*	1.35E-02	*4.52E-03*	6.59E-03		2,3,4,7,8-PeCDF	6.59E-03	X	0.5	=	3.30E-03
1,2,3,6,7,8-HxCDF	2.52E-03	4.05E-03	*4.52E-03*	3.70E-03		1,2,3,6,7,8-HxCDF	3.70E-03	X	0.1	=	3.70E-04
1,2,3,7,8,9-HxCDF	*2.27E-03*	*1.69E-03*	*9.03E-03*	0.00E+00		1,2,3,7,8,9-HxCDF	0.00E+00	X	0.1	=	0.00E+00
1,2,3,4,7,8-HxCDF	1.01E-02	2.02E-02	1.81E-02	1.61E-02		1,2,3,4,7,8-HxCDF	1.61E-02	X	0.1	=	1.61E-03
2,3,4,6,7,8-HxCDF	1.01E-02	2.02E-02	*9.03E-03*	1.31E-02		2,3,4,6,7,8-HxCDF	1.31E-02	X	0.1	=	1.31E-03
1,2,3,4,6,7,8-HpCDF	5.04E-02	5.40E-02	1.26E-01	7.70E-02		1,2,3,4,6,7,8-HpCDF	7.70E-02	X	0.01	=	7.70E-04
1,2,3,4,7,8,9-HpCDF	5.04E-03	4.05E-03	*9.03E-03*	6.04E-03		1,2,3,4,7,8,9-HpCDF	6.04E-03	X	0.01	=	6.04E-05
OCDF	1.31E-01	1.28E-01	3.79E-01	2.13E-01		OCDF	2.13E-01	X	0.001	=	2.13E-04
									CDF Subtotal	=	9.82E-03
									Total	=	1.48E-02

	Typical Reformation Rate (ng/g/min)	Fly Ash Mass in Flue gas (g/min)	Time in Reformation temp. Region (min)	Min. Flow Rate through Reformation Region (m^3/min)		Estimated TM-17 reformed concentration	Conversion ratio				Toxicity Equivalent (TEQ)-ng/m3
De Novo Synthesis (Reformation)-w/150 ug/m^3 chlorophenol precursor	3300	52.92	0.02162162	5.47E+03		0.690926535	1.06E+02				6.54E-03
TM-17 + De Novo Synthesis						6.91E-01					**2.13E-02**

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

From: Dave Strohm <dstrohm@jbrenv.com>
Sent: Thursday, May 24, 2012 8:38 AM
To: Darrin Pampaian
Subject: Dynamis Emissions Factors Development
Attachments: Emission Factor Development_051512_for DEQ.xls

Darrin,

Shannon ask if I would pass along the emissions factor development spreadsheet to you for the Dynamis project. This spreadsheet was used to summarize the available source test data and determine the emissions factors that were used in support of the Ada County PTC. Please feel free to call Shannon or I if you have any questions.

Best,
Dave

JBR Environmental Consultants, Inc.
David E.B. Strohm II
Project Manager
7669 West Riverside Drive, Suite 101
Boise, ID 83714
208.853.0883 (phone)
208.853.0884 (fax)
415.686.8898 (cell)

Source Test References

Test Reference Number	Report Title	Author(s)	Additional Information	Data Included in Tests
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2	December 1990 Municipal Solid Waste Burn Test in an Entech Therma Oxidation Demonstation Plant at Western Research Institute. February 1991, revised April 1991. For: Entech, Inc., Anchorage, Alaska	John Nordin, George Huntington	December 3 Burn	CO2, NOx, FH PM, BH PM, HCl, Metals, Dioxin/Furan, SO2, CO, Ash
3	December 1990 Tire Burn Test in an Entech Thermal Oxidation Demonstation Plant at Western Research Institute. February 1991. For: Entech, Inc., Anchorage, Alaska	John Nordin, George Huntington	December 5 and December 7 Burns	CO2, NOx, FH PM, BH PM, HCl, Metals, SO2, CO, Ash
4	September 1991 Tire Burn Test in an Entech Thermal Oxidation Demonstration Plant at Western Research Institute. January 1992. Fo Entech, Inc., Anchorage, Alaska.	John Nordin	September 17 Burn	CO2, NOx, SO2, CO

Important Notes:

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average

If all samples are non-detect (less than), average will be zero.

All data available in the source tests listed above was used to develop the emissions factors.

Source Test Result Summary

Test	Summary								
	NOx (ppm)	FH PM (mg/m^3)	BH PM (mg/m^3)	Total PM (mg/m^3)	HCl (ppm)	Dioxins/Furans (mg/m^3)	SO2 (ppmv)	CO (ppmv)	CO2 (%)
Test 1A-1C: April-May 1993 Entech Model TOS-8	90	37	21	58	42	7.28E-06	n/a	n/a	10
Test 2: December 1990 MSW Burn Test	33	1.5	<1.157	3	17	5.53E-06	2.6	7.8	6.8
Test 3: December 1990 Tire Burn Test	70	19	9.9	29	7.8	n/a	138	103	11
Test 4: September 1991 Tire Burn Test	105	n/a	n/a	n/a	n/a	n/a	19	22	8.6
Average	***75***	***19***	***11***	***30***	***22***	***6.40E-06***	***53***	***44***	***9.0***

Metals	Test 1A-1C: April-May 1993 Entech Model TOS-80 (mg/m^3)	Test 2: December 1990 MSW Burn Test (mg/m^3)	Test 3: December 1990 Tire Burn Test (mg/m^3)	Average (mg/m^3)
Ag	no data	<0.0003	0	0
Al	no data	0.064	0.031	0.048
As	0	<0.004	0	0.000
B	no data	0.012	0.015	0.014
Ba	no data	0.0015	0.001	0.001
Be	0	<0.00008	0	0.000
Bi	no data	<0.004	0.010	0.007
Ca	no data	0.31	0.128	0.219
Cd	0.052	0.0059	0.004	0.021
Co	no data	<0.0003	0.001	0.002
Cr	0.028	0.0003	0.003	0.010
Cu	no data	0.002	0.007	0.004
Fe	no data	0.037	0.043	0.040
K	no data	<2	0	0.000
Li	no data	0.0007	0.001	0.001
Mg	no data	0.029	0.056	0.042
Mn	0.077	0.001	0.030	0.036
Mo	no data	0.005	0.021	0.013
Na	no data	0.25	0.418	0.334
Ni	0.227	<0.0008	0.033	0.089
P	no data	<0.04	0	0.000
Pb	0.326	0.04	0.072	0.146
Sb	0	<0.004	0.01	0.005
Se	no data	<0.004	0.003	0.004
Sr	no data	0.001	0.001	0.001
Th	no data	<0.002	0	0.000
V	no data	<0.0003	0	0.000
Zn	0.651	0.11	1.27	0.678
Hg*	0.049	no data	no data	0.015

Hg - reduced from information (various literature sources) regarding the reduction in incoming waste stream/untreated flue gas mercury content. Conservatively estimate a 70% reduction in mercury content of incoming waste, therefore reduce source test average concentration by 70%.

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Emission Factor Calculation

Pollutant	Source Test Average	AP-42 Conversion Factor	lb/ton Emission Factor
PM (mg/m^3)	29.7	9.85E-03	2.93E-01
NOx (ppm)	74.5	1.89E-02	1.41E+00
SO2 (ppm)	53.1	2.62E-02	1.39E+00
CO (ppm)	44.3	1.15E-02	5.10E-01
HCl (ppm)	22.3	1.50E-02	3.35E-01
CDD/CDF (ug/m^3)	6.40E-03	9.85E-06	6.31E-08
CO2 (ppm)	9 04E+04	1.47E-02	1.33E+03
Metals (ug/m^3):			
Ag	0.00	9.85E-06	0.00E+00
Al	48	9.85E-06	4.70E-04
As	0.00	9.85E-06	0.00E+00
B	14	9.85E-06	1.35E-04
Ba	1.3	9.85E-06	1.23E-05
Be	0.00	9.85E-06	0.00E+00
Bi	7.2	9.85E-06	7.06E-05
Ca	219	9.85E-06	2.16E-03
Cd	21	9.85E-06	2.02E-04
Co	1.8	9.85E-06	1.77E-05
Cr	10	9.85E-06	1.03E-04
Cu	4.4	9.85E-06	4.33E-05
Fe	40	9.85E-06	3.95E-04
K	0.00	9.85E-06	0.00E+00
Li	0 9	9.85E-06	9.03E-06
Mg	42	9.85E-06	4.17E-04
Mn	36	9.85E-06	3.56E-04
Mo	13	9.85E-06	1.30E-04
Na	334	9.85E-06	3.29E-03
Ni	89	9.85E-06	8.81E-04
P	0.00	9.85E-06	0.00E+00
Pb	146	9.85E-06	1.44E-03
Sb	4.7	9.85E-06	4.60E-05
Se	3.5	9.85E-06	3.45E-05
Sr	0.8	9.85E-06	8.21E-06
Th	0.00	9.85E-06	0.00E+00
V	0.00	9.85E-06	0.00E+00
Zn	678	9.85E-06	6.68E-03
Hg	15	9.85E-06	1.45E-04

AP-42 conversion factor from AP-42, Chapter 2.1, Table 2.1-11.

For test results showing 'less han' (non-detect), use the number following the 'less han' to calculate the average
If all samples are non-detect (less than), average will be zero

Ash Analysis

Constituent	Test 1A-1C: April-May 1993 Entech Model TOS-80 (mg/kg)	Test 2: December 1990 MSW Burn Test (mg/kg)	Test 3: December 1990 Tire Burn Test (mg/kg)	Average (mg/kg)
Ag	0.37	<7	0	0.19
Al	no data	86000	37250	61625
As	0.00	<100	0	0 00
B	no data	450	160.5	305
Ba	4.21	890	189 5	361
Be	no data	<2	0	0 00
Bi	no data	<100	0	0 00
Ca	no data	79000	20425	49713
Cd	4.11	<10	13.725	9.3
Co	no data	12	1780	896
Cr	0.27	130	33	54
Cu	no data	330	149	240
Fe	no data	24000	7325	15663
Hg	0.00	na	0	0 00
K	no data	<49,000	0	0 00
Li	no data	39	61	50
Mg	no data	7700	4850	6275
Mn	no data	1000	115	558
Mo	no data	<10	17.05	14
Na	no data	2800	5725	4263
Ni	no data	29	46.5	38
p	no data	1100	2300	1700
Pb	12 33	490	475	326
Sb	no data	<100	0	0 00
Se	0.00	<100	0	0 00
Sr	no data	210	91.25	151
Th	no data	<50	0	0 00
V	no data	36	41.75	39
Zn	no data	3100	287500	145300

Test 1A-1C: April-May 1993 Entech Model TOS-80		
Volume 2- Table A2		
Burn	Sample	% CO2
1	A	9.5
	B	9.5
	C	6.3
	organics	9.5
	metals	9.5
2	A	13.2
	B	12.6
	C	10.4
	organics	12.4
	metals	10.4
4	A	12.7
	B	10.9
	C	6
	organics	10.9
	metals	8
Average		10.12

Test 2: December 1990 Municipal Solid Waste Burn Test	
Table 3 - December 3 Burn NOx and SO2 measurement	
Time	%CO2
8:35	6.1
9:22	6.4
9:50	5.6
10:15	7.6
10:45	7.5
11:15	10.1
11:40	8.6
12:15	8.2
12:40	8.1
13:20	7.3
13:40	7.5
14:15	5.8
14:40	6.2
15:00	5.7
15:20	5.3
15:40	4.1
16:15	3.2
Average	6.45

Upset condition at 11:15, do not use in average (shaded gray cells)

Test 2: December 1990 Municipal Solid Waste Burn Test	
Table 5 - Particulate and HCl Measurement	
CO2%	6.08

Test 2: December 1990 Municipal Solid Waste Burn Test	
Table 7 - Dioxin/Furan Measurement	
Average CO2%	7.9

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 3: December 1990 Tire Burn Test	
Table 2 - December 5 Burn CO and NOx measurement	
Time	% CO2
11:55	9.3
12:12	10.5
12:50	7
13:05	10.1
13:15	14.1
14:08	11.6
14:20	8.5
14:55	13.5
15:35	11.1
15:55	8.7
16:45	7.1
17:00	7.1
17:15	7.5
Average	9.7

Test 3: December 1990 Tire Burn Test	
Table 8 - Particulate and HCL Measurement	
5-Dec Avg CO2%	11.2
7-Dec Avg CO2%	10.9

Test 4: September 1991 Tire Burn Test	
Table 2 - Secondary Chamber Emissions	
Time	%CO2
9:55	9.8
10:25	9.4
10:55	9.5
11:25	9.3
11:55	9.2
12:25	8.7
13:20	9.5
13:50	6.4
14:20	5.9
Average	8.6

Test 1A-1C April-May 1993 Entech Model TOS-80

Table 4. Enerac 2000 NOx Readings

Burn	Time	NOx (ppm)
1	12:06	105
2	7:19	71
	7:55	138
	8:43	177
	9:14	109
	10:48	60
	11:35	47
	12:04	30
	14:43	53
	15:24	57
	16:30	60
4	7:17	71
	8:17	87
	8:20	89
	8:45	141
	9:40	161
	9:47	171
	10:00	67
	15:16	15
Average =		89.9

Test 2 December 1990 Municipal Solid Waste Burn Test

Table 3. Secondary Combustion Emissions, December 3 Burn

Time	%O2	NOx (ppm)	NOx (ppm) correct to 7% O2
8:35	10.3	11	14.4
8:55	no reading	no reading	---
9:22	10.2	19	24.7
9:50	11.7	30	45.3
10:15	7.6	45	47.0
10:45	7.8	40	42.4
11:15	2.9	76	58.7
11:40	5.4	33	29.6
12:15	6.4	31	29.7
12:40	6.8	22	21.7
13:20	8.1	19	20.6
13:40	7.6	19	19.9
14:15	10.4	22	29.1
14:40	9.9	25	31.6
15:00	10.8	22	30.3
15:20	11.6	19	28.4
15:40	13.9	19	37.7
16:00	no reading	no reading	---
16:15	15.8	19	51.8
Average =			33.1

Test 3 December 1990 Tire Burn Test

Table 2. Secondary Combustion Emissions, December 5 Burn

Time	%O2	NOx (ppm)	NOx (ppm) correct to 7% O2
11:55	8.6	21	23.7
12:12	7	42	42.0
12:50	11.3	71	102.8
13:05	7.6	130	135.9
13:15	2.5	191	144.3
13:18	1.5	no data	---
0:13	0.7	no data	---
13:57	2.3	no data	---
14:08	5.5	145	130.9
14:11	no data	no data	---
14:20	9.7	112	139.0
14:55	2.8	59	45.3
15:35	6.1	30	28.2
15:55	9.3	20	24.0
16:20	no data	no data	---
16:45	11.5	22	32.5
17:00	11.4	22	32.2
17:15	10.9	22	30.6
Average=			70.1

Test 4 September 1991 Tire Burn Test

Table 2. Secondary Combustion Chamber Emissions

Time	%O2	NOx (ppm)	NOx (ppm) correct to 7% O2
9:55	3.7	140	113
10:25	4.3	172	144
10:55	4 2	172	143
11:25	4 9	130	113
11:55	4 5	126	107
12:25	5 6	95	86
13:20	3 8	107	87
13:50	9.7	65	81
14:20	10.4	53	70
14:20	Shutdown		
Average=			105

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 1A-1C: April-May 1993 Entech Model TOS-80

Table 5. Front Half Particulates Corrected to 7% O2 Basis

Burn	Sample	% O2	Part. @ 7% O2 (gr/dscf)	Part. @ 7% O2 (mg/m^3)
1	A	8.8	0.57	1310
	B	8.8	<0.001	<2
	C	12	0.028	63
2	A	3	0.018	41
	B	4	0.009	20
	C	8.9	0.005	10.5
4	A	5.1	0.012	26.7
	B	7.4	0.019	42.4
	C	13	0.038	86.9
Average=				36.6

*Do not use Burn 1, Sample A (shaded gray cells). Operator was experimenting with operating parameters during test, not typical operation of unit.

Test 2: December 1990 Municipal Solid Waste Burn Test

Table 5. Particulate Emissions from Secondary Combustion Unit, December 3, 1990

Fronthalf particulates; mg/m3	3-Dec
As collected	1.12
7% O2 basis	1.46
Backhalf particulates; mg/m3	
As collected	<0.926
7% O2 basis	<1.157

Test 3: December 1990 Tire Burn Test

Table 5. Particulate Emissions from Secondary Combustion Unit, December 3, 1990

Date	5-Dec	7-Dec	7-Dec	Average
Fronthalf particulates; mg/m3				
As collected	19.11	74.97	19.16	
7% O2 basis	18.07	76.36	19.67	18.87
Backhalf particulates; mg/m3				
As collected	<0.69	18.74	18.74	
7% O2 basis	<0.69	19.21	19.21	9.95

*December 7 first sample - do not use (shaded gray cells). Upset conditions caused considerable soot on he filter.

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average

If all samples are non-detect (less than), average will be zero.

Test 1A-1C April-May 1993 Entech Model TOS-80

Table 6. Back Half Particulates Corrected to 7% O2

Burn	Sample	% O2	Part. @ 7% O2 (gr/dscf)	Part. @ 7% O2 (mg/m^3)
1	A	8.8	0.042	96.8
	B	8.8	0 0057	13.1
	C	12	0.015	34.1
2	A	3	0 0005	1.2
	B	4	0.002	5.3
	C	8.9	0.007	16.6
4	A	5.1	0.003	7.4
	B	7.4	0.016	35.6
	C	13	0.024	55.6
Average				21.1

was experimenting with operating parameters during test, not typical operation of unit.

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 2 December 1990 Municipal Solid Waste Burn Test

Table 5. Particulate Emissions from Secondary Combustion Unit, December 3, 1990

Fronthalf particulates; mg/m3	3-Dec
As collected	1.12
7% O2 basis	1.46
Backhalf particulates; mg/m3	
As collected	<0.926
7% O2 basis	<1.157

Test 3 December 1990 Tire Burn Test

Table 5. Particulate Emissions from Secondary Combustion Unit, December 3, 1990

	5-Dec	7-Dec	7-Dec	Average
Fronthalf particulates; mg/m3				
As collected	19.11	74.97	19.16	
7% O2 basis	18.07	76.36	19.67	18.87
Backhalf particulates; mg/m3				
As collected	<0.69	18.74	18.74	
7% O2 basis	<0.69	19.21	19.21	9.95

*December 7 first sample - do not use (shaded gray cells). Upset conditions caused considerable soot on the filter.

Test 1A-1C: April-May 1993 Entech Model TOS-80

Table 7. Hydrogen Chloride Emissions

Burn	Sample	%O2	ppm HCl, as measured	ppm HCl @ 7% O2
1	A	8.8	50.0	57.4
	B	8.8	61.5	70.6
	C	12	55.3	35.6
2	A	3	101.6	78.6
	B	4	18.3	14 9
	C	8.9	26.8	30 9
4	A	5.1	68.5	60.4
	B	7.4	6.0	6.2
	C	13	12.7	22 2
Average				41 9

For test results showing 'less than' (non-detect), use the number following the 'less han' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 2: December 1990 Municipal Solid Waste Burn Test

Table 5. HCl Emissions from Secondary Combustion Unit, December 3, 1990

Date	3-Dec
HCl, ppm by volume (dry basis)	17.3

Test 3: December 1990 Tire Burn Test

Table 8. HCl Emissions from Secondary Combustion Unit

Date	5-Dec	7-Dec	7-Dec	Average
HCl, ppm by volume (dry basis	3.4	10	10	7.8

Test 1A-1C April-May 1993 Entech Model TOS-80

Table 9. Metal Emissions Corrected to a 7% Oxygen Basis, mg/m^3

Burn	1	2	4	Average
% O2	8.7	6 8	10.3	8 60
As	<0.3	<0.25	<0.04	0 00
Be	<0.0006	<0.0005	<0 0007	0 00
Cd	0.0025	0.15	0.0037	0 05
Cr	<0.001	0.046	0 036	0 03
Hg	0.014	0.132	<0.001	0 05
Mn	<0 01	0.016	0 206	0 08
Ni	0.014	0.068	0.6	0 23
Pb	0.042	0.922	0 014	0 33
Sb	<0 02	<0.02	<0.04	0 00
Tl	<0 01	<0.01	<0.02	0 00
Zn	1	0.7	0 252	0 65

Test 2 December 1990 Municipal Solid Waste Burn Test

Table 6. Fronthalf Particulate Elemental Analysis

Element	Conc. Corrected to 7% O2 Basis (mg/m3)
Ag	<0.0003
Al	0.064
As	<0.004
B	0.012
Ba	0 0015
Be	<0 00008
Bi	<0.004
Ca	0.31
Cd	0 0059
Co	<0.0003
Cr	0 0003
Cu	0.002
Fe	0.037
K	<2
Li	0 0007
Mg	0.029
No	0.001
Mo	0.005
Na	0.25
Ni	<0.0008
P	<0 04
Pb	0.04
Sb	<0.004
Se	<0.004
Sr	0.001
Th	<0.002
V	<0.0003
Zn	0.11

Test 3 December 1990 Tire Burn Test

Table 9. Fronthalf Particulate Elemental Analysis, December 5 Burn

Element	Conc. Corrected to 7% O2 Basis (mg/m3)
Ag	<0.0002
Al	0.04
As	<0 003
B	0.03
Ba	0 001
Be	<0.0001
Bi	<0 003
Ca	0.134
Cd	0 002
Co	0 001
Cr	0.0043
Cu	0.0064
Fe	0.0124
K	<2
Li	0 001
Mg	0 052
Mn	0.03
Mo	0 032
Na	0 355
Ni	0 033
P	<0 003
Pb	0 037
Sb	<0 003
Se	<0 003
Sr	0.0005
Th	<0 002
V	<0.0003
Zn	0.143

Test 3 December 1990 Tire Burn Test

Table 10. Fronthalf Particulate Elemental Analysis, December 7 Burn

Element	Sample 1 Conc. Corrected to 7% O2 Basis (mg/m3)	Sample 2 Conc. Corrected to 7% O2 Basis (mg/m3)	Average of Dec-5 and Dec-7 Burns
Ag	<0.0004	<0 0004	0.000
Al	0 048	0.006	0.031
As	<0 005	<0.005	0.000
B	0 014	0.002	0.015
Ba	0 001	0.001	0.001
Be	no data	no data	0.000
Bi	0 023	<0.005	0.010
Ca	0.18	0.07	0.128
Cd	0 008	0.001	0.004
Co	<0.0004	<0 0004	0.001
Cr	0 003	0.003	0.003
Cu	0 007	0.007	0.007
Fe	0 062	0.055	0.043
K	<3	<3	0.000
Li	0.0014	<0.001	0.001
Mg	0.06	0.055	0.056
Mn	0.03	0.03	0.030
Mo	0 016	0.016	0.021
Na	0.466	0.434	0.418
Ni	no data	no data	0.033
P	<0.06	<0.06	0.000
Pb	0.14	0.039	0.072
Sb	0 024	0.003	0.010
Se	0 003	0.003	0.003
Sr	0 001	<0 0005	0.001
Th	<0 002	<0.002	0.000
V	<0.0005	<0 0005	0.000
Zn	3.05	0.63	1.274

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the averag
If all samples are non-detect (less than), average will be zero

Test 1A-1C April-May 1993 Entech Model TOS-80

Table 11. Dioxins/Furans Corrected to a 7% Oxygen Basis, mg/m^3

Burn	1	2	4	Average		Compound	Concentration		Toxicity Equivalency Factor (TEF)		Toxicity Equivalent (TEQ)
% Oxygen	8.70E-06	4.40E-06	7.30E-06	6.80E-06		Units:	mg/m3				mg/m3
Total TCDD	4.16E-06	ND	6.80E-09	1.39E-06		2,3,7,8-TCDD	1.39E-06	X	1	=	1.39E-06
Total PeCDDD	4.16E-06	ND	1.30E-08	1.39E-06		2,3,7,8-PeCDDs	1.39E-06	X	0.5	=	6.96E-07
Total HxCDD	8.18E-06	2.50E-08	4.80E-08	2.75E-06		2,3,7,8-HXCDDs	2.75E-06	X	0.1	=	2.75E-07
Total HpCDD	6.44E-06	1.90E-07	2.20E-07	2.28E-06		2,3,7,8-HpCDDs	2.28E-06	X	0.01	=	2.28E-08
OCDD	4 02E-06	6.50E-07	8.90E-07	1.85E-06		OCDD	1.85E-06	X	0.001	=	1.85E-09
Total TCDF	7 64E-05	1.50E-08	1.40E-07	2.55E-05					CDD Subtotal	=	2.38E-06
Total PeCDF	5.46E-05	1.50E-08	6.00E-08	1.82E-05		2,3,7,8-TCDF	2.55E-05	X	0.1	=	2.55E-06
Total HxCDF	4.13E-05	1.00E-07	1.20E-07	1.38E-05		1,2,3,7,8-PeCDF	1.82E-05	X	0.05	=	9.12E-07
Total HpCDF	1 29E-05	2.40E-07	2.20E-07	4.44E-06		2,3,7,8-HxCDFs	1.38E-05	X	0.1	=	1.38E-06
OCDF	1 81E-06	EMPC (1.30E-07)	1.30E-07	6.90E-07		2,3,7,8-HpCDFs	4.44E-06	X	0.01	=	4.44E-08
Totals	2.14E-04	1.40E-06	1.86E-06	7.24E-05		OCDF	6.90E-07	X	0.001	=	6.90E-10
									CDF Subtotal	=	4.89E-06
									Total	=	7.28E-06

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 2 December 1990 Municipal Solid Waste Burn Test

Table 10. Dioxins/Furans Emissions from Secondary Combustion Unit, December 11 Burn

Compound	Concentration
Dioxins (PCDD), mg/m3, 7% O2 basis	1.92E-06
Furans (PCDF), mg/m3, 7% O2 basis	3.61E-06
Total	5.53E-06

Test 2: December 1990 Municipal Solid Waste Burn Test

Table 3. Secondary Combustion Emissions, December 3 Burn

Time	%O2	ppm SO2	SO2 (ppm) corrected to 7% O2
8:35	10.3	<2	2.62
8:55	no reading	no reading	no reading
9:22	10.2	<2	2.60
9:50	11.7	<2	3.02
10:15	7.6	<2	2.09
10:45	7.8	<2	2.12
11:15	2.9	<2	1.54
11:40	5.4	<2	1.79
12:15	6.4	<2	1.92
12:40	6.8	<2	1.97
13:20	8.1	<2	2.17
13:40	7.6	<2	2.09
14:15	10.4	<2	2.65
14:40	9.9	<2	2.53
15:00	10.8	<2	2.75
15:20	11.6	<2	2.99
15:40	13.9	no reading	3.97
16:00	no reading	no reading	no reading
16:15	15.8	<2	5.45
Average			2.60

Test 3: December 1990 Tire Burn Test

Table 3. Secondary Combustion Chamber Sulfur Dioxide Emissions

Date	Average SO2 (ppm)
5-Dec	199
7-Dec	76
Average	137.5

Test 4: September 1991 Tire Burn Test

Table 2. Secondary Combustion Chamber Emissions

Time	%O2	ppm SO2	SO2 (ppm) corrected to 7% O2
9:55	3.7	15	12.1
10:25	4.3	22	18.4
10:55	4.2	15	12.5
11:25	4.9	25	21.7
11:55	4.5	37	31.4
12:25	5.6	13	11.8
13:20	3.8	30	24.4
13:50	9.7	18	22.3
14:20	10.4	Not taken	Not taken
14:20	Shutdown		
Average			19.3

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 2: December 1990 Municipal Solid Waste Burn Test			
Table 3. Secondary Combustion Emissions, December 3 Burn			
Time	%O2	ppm CO	CO (ppm) corrected to 7% O2
8:35	10.3	5	6.6
8:55	no reading	no reading	no reading
9:22	10.2	13	16.9
9:50	11.7	3	4.5
10:15	7.6	3	3.1
10:45	7.8	5	5.3
11:15	2.9	65	50.2
11:40	5.4	3	2.7
12:15	6.4	13	12.5
12:40	6.8	<2	2.0
13:20	8.1	<2	2.2
13:40	7.6	<2	2.1
14:15	10.4	<2	2.6
14:40	9.9	3	3.8
15:00	10.8	<2	2.8
15:20	11.6	<2	3.0
15:40	13.9	<2	4.0
16:00	no reading	no reading	no reading
16:15	15.8	3	8.2
Average			7.8

Test 3: December 1990 Tire Burn Test			
Table 2. Secondary Combustion Emissions, December 5 Burn			
Time	%O2	ppm CO	CO (ppm) corrected to 7% O2
11:55	8.6	8	9.0
12:12	7	3	3.0
12:50	11.3	33	47.8
13:05	7.6	10	10.5
13:15	2.5	47	35.5
13:18	1.5	220	158
0:13	0.7	200	138
13:57	2.3	1500	1121
14:08	5.5	35	31.6
14:11	no data	47	no data
14:20	9.7	45	55.8
14:55	2.8	28	21.5
15:35	6.1	13	12.2
15:55	9.3	<2	2.4
16:20	no data	no data	no data
16:45	11.5	<2	3.0
17:00	11.4	<2	2.9
17:15	10.9	<2	2.8
Average			103.4

Test 4: September 1991 Tire Burn Test			
Table 2. Secondary Combustion Chamber Emissions			
Time	%O2	ppm CO	CO (ppm) corrected to 7% O2
9:55	3.7	39	31.5
10:25	4.3	30	25.1
10:55	4.2	28	23.3
11:25	4.9	20	17.4
11:55	4.5	23	19.5
12:25	5.6	21	19.1
13:20	3.8	21	17.1
13:50	9.7	18	22.3
14:20	10.4	16	21.2
14:20	Shutdown		
Average			21.8

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Test 1A-1C: April-May 1993 Entech Model TOS-80					
Metal	Burn 1 (mg/L)	Burn 2 (mg/L)	Burn 4 (mg/L)	Average (mg/L)	Average (mg/kg)
Ag	<0.007	<0.007	0.042	0 02	0.37
Al	no data				
As	<0.100	<0.005	<0.005	0 00	0.00
B	no data				
Ba	0.398	0.155	0.079	0 21	4.21
Be	no data				
Bi	no data				
Ca	no data				
Cd	0.174	0.073	0.37	0 21	4.11
Co	no data				
Cr	<0.008	0.025	<0.008	0 01	0.27
Cu	no data				
Fe	no data				
Hg	<0.002	<0.002	<0.002	0 00	0.00
K	no data				
Li	no data				
Mg	no data				
Mn	no data				
Mo	no data				
Na	no data				
Ni	no data				
p	no data				
Pb	0.421	0.098	1.33	0.62	12.33
Sb	no data				
Se	<0.100	<0.050	<0.05	0 00	0.00
Sr	no data				
Th	no data				
V	no data				
Zn	no data				

*From literature, mg/kg can be approximated by 20*mg/L.

Test 2: December 1990 Municipal Solid Waste Burn Test	
Metal	Concentration (mg/kg)
Ag	<7
Al	86,000
As	<100
B	450
Ba	890
Be	<2
Bi	<100
Ca	79,000
Cd	<10
Co	12
Cr	130
Cu	330
Fe	24,000
Hg	na
K	<49,000
Li	39
Mg	7,700
Mn	1,000
Mo	<10
Na	2,800
Ni	29
p	1,100
Pb	490
Sb	<100
Se	<100
Sr	210
Th	<50
V	36
Zn	3,100

Test 3: December 1990 Tire Burn Test					
Metal	Dec 5 Burn (mg/kg)	Dec 7 Sample 1 (mg/kg)	Dec 7 Sample 2 (mg/kg)	Dec 7 Sample 3 (mg/kg)	Average (mg/kg)
Ag	<6 5	<6.8	<6.9	<5.8	0
Al	35,000	30,000	38,000	46,000	37250
As	<92	<98	<98	<82	0
B	102	110	210	220	161
Ba	130	<98	350	180	190
Be	<1 8	<2	<2	<1.6	0
Bi	<92	<98	<98	<82	0
Ca	50,000	2,700	18,000	11,000	20425
Cd	15	11	20	8.9	14
Co	720	2,000	2,300	2,100	1780
Cr	31	20	40	41	33
Cu	76	140	220	160	149
Fe	8,700	5,200	8,500	6,900	7325
Hg	no data				
K	<47,000	<49,000	<49,000	<42,000	0
Li	39	63	50	92	61
Mg	3,400	5,300	6,500	4,200	4850
Mn	160	74	130	96	115
Mo	<9 2	15	24	20	17
Na	4,100	5,200	8,000	5,600	5725
Ni	31	24	87	44	47
P	1,700	2,900	1,800	2,800	2300
Pb	530	280	520	570	475
Sb	<92	<98	<98	<82	0
Se	<92	<98	<98	<82	0
Sr	140	57	72	96	91
Th	<46	<49	<49	<41	0
V	20	35	57	55	42
Zn	130,000	320,000	380,000	320,000	287500

For test results showing 'less than' (non-detect), use the number following the 'less than' to calculate the average
If all samples are non-detect (less than), average will be zero.

Dynamis Energy LLC 12/6/2010 **Model 250 TOS**

Ada County Landfill Combustion, Particulate Discharge Calculations:

Waste Reduction & Thermal Recycle 3.0 Standard TOS System

Assume the Following

MSW Receiving Per Day Max Without Lime Inject.	408	Tons Per Day	
Days Per Week	7	Days Receiving	
Tons Per Week	2856	Tons Per Week	
Hours Per Week of Operation	168	Hours of Operation per Week	
Pounds Per Ton	2,000		

Discharge

HF. @	0.005	MG/Nm3	0.0001	5E-07	PPH / lb
Grains per lb / hr	27.6	0.0001812 PPH / lb		12.51075	PPH
Discharge PPH	0.00227	Lbs / Hour		8760	Hours Yr
Total lbs Year Discharge	19.85	lbs Year discharge			
Total Tons per Year	0.01	Tons per Year Discharge of Particulate			
Emission Factor	1.34E-04	lb/ton			

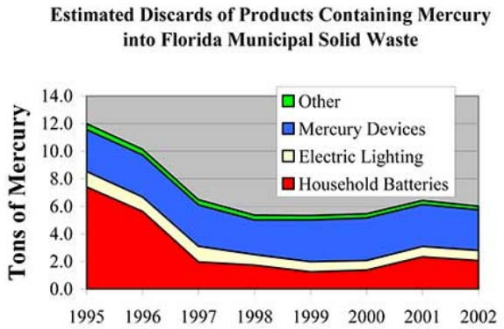
*Emissions estimates for HF were developed by Roger Kolb, Dynamis. The original source of the data could not be located. However, asuuming emissions of HF from the thermal conversion unit is conservative due to the fact that emissions compiled by EPA and used to develop emissions factors for AP-42 do not consider HF as an emission from MSW starved air combustion.

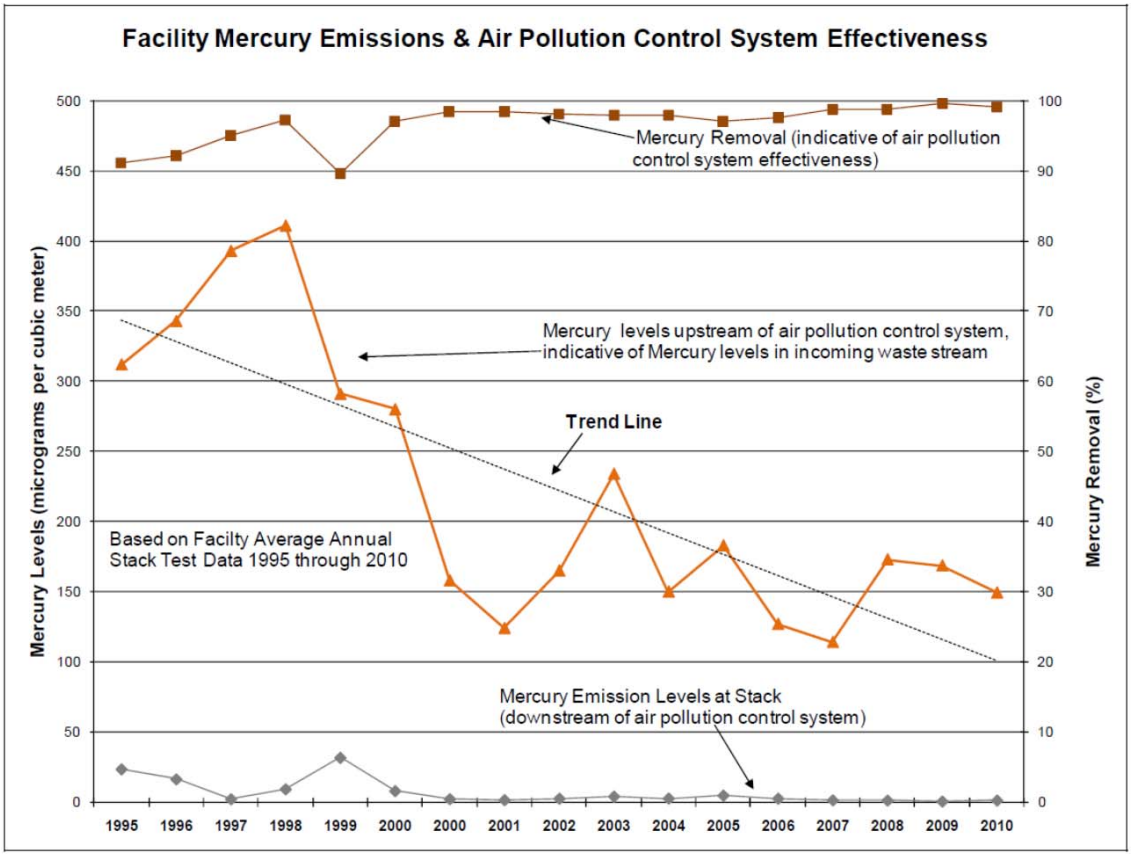
Mercury Reduction Information

"The use of mercury in the US decreased from 3000 tonnes per year in the 1970s to less than 400 tonnes by the end of the century"

Source
Themelis,N J. and Gregory, A., Mercury Emissions from High Temperature Sources in Hudson Basin, Proceedings NAWTEC 10, Solid Wastes Processing Division, ASME International, pp 205-215 (May 2002).

Quantifying Mercury in Florida's Solid Waste Page
|http://www dep state.fl.us/waste/categories/mercury/pages/sources_and_quantities.htm





Source:
Onondaga County, Resource Recovery Facility,
NYSDEC Part 360 Permit D No. 7-3142-00028/00011
Title V Air Permit D No. 7-3142-00028/00009
Annual Report of Facility Performance, Operating Year 2010
Onondaga County Resource Recovery Agency
WWW.OCRRA.ORG
Prepared May 2011

creating solutions for today's environment

June 11, 2012

Mr. Darrin Pampaian, P.E.
Idaho DEQ - Air Quality Division
1410 North Hilton
Boise, Idaho 83706-1255

Re: Facility ID No. 001-00252, Dynamis Energy, LLC, Boise
Permit to Construct Application Incompleteness, Installation of a New Waste-to-Energy Facility to be Located at the Hidden Hollow Landfill

On April 25, 2012, JBR Environmental Consultants, Inc. (JBR), on behalf of Dynamis Energy, LLC (Dynamis) submitted a 15-Day Pre-Permit Construction Approval (15-Day) Application and Permit to Construct (PTC) Application for the proposed Dynamis Waste-to-Energy (WTE) facility at the Hidden Hollow Landfill in Ada County, ID. DEQ reviewed the application materials and determined that the application is incomplete. The purpose of this letter is to provide the requested information for DEQ to determine the application complete.

Items requested from DEQ, along with response from JBR and Dynamis are shown below.

Bullet Item #1: The basis and methodology used to establish emissions from the Thermal Conversion Unit.

JBR provided, via email on 5/24/2012, an Excel spreadsheet documenting the source test information and emission factor calculations used to establish emissions from the Thermal Conversion Unit.

Bullet Item #2: The nitrogen dioxide (NO_2) Significant Impact Level (SIL) the modeling group received on May 8th contained ambient impacts based on the refined Tier 3 NO_2 modeling methods. The maximum daily 1-hr average NO_2 impacts were predicted to exceed the 7.5 µg/m^3, 1-hr average SIL at the outermost eastern and northern portions of the receptor grid. The receptor grid used does not capture the extent of the area where the project is expected to cause a significant impact. This comment also applies to the SO_2, 1-hr average,

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SIL analysis. Comment 5 of the modeling protocol requested that this project's modeling use a receptor grid that covers all areas where the proposed project causes a significant ambient impact.

Revised modeling files are included with this submittal. The revised modeling files include the use of an expanded receptor grid to ensure that all impacts above the SIL are captured.

Bullet Item #3: The NO_2 SIL modeling used a value of 0.15 for the in-stack NO_2 to NO_X ratio for all sources at the facility. However, the facility-wide analysis used an in-stack ratio of 0.5 for the Dynamis Energy emergency IC engine. Please confirm the in-stack ratios of NO_2 to NO_X for all sources in the analysis.

The revised 1-hr NO_x modeling files use corrected NO_2 to NO_x in-stack ratios as follows:

- Thermal Unit NO_2 to NO_x ratio: 0.15
- Dynamis Emergency Generator NO_2 to NO_x ratio: 0.20
- ACLF Diesel Generators NO_2 to NO_x ratio: 0.20
- All other sources NO_2 to NO_x ratio: 0.50 (default)

Bullet Item #4: The exhaust parameters for the emergency IC engine appear to have a high exhaust temperature and flow rate for a 40 feet high release height as proposed (assuming the emergency IC engine itself is located at base elevation of the site). Stack temperatures provided by the IC engine manufacturer are representative of the "stack height" as-delivered prior to any stack height increases. Additional validation is needed for the exhaust parameters for this source or remodel with more conservative assumptions, if remodeling is performed.

Dynamis and JBR reviewed the information provided by the generator manufacturer. As stated by DEQ, stack temperatures provided by the engine manufacturer are representative of the 'as-delivered' stack height; the 'as-delivered' stack height of the Caterpillar emergency generator is five feet. The generator will sit on a skid approximately feet off the ground, for a total stack height of 10 feet above ground surface. Revised modeling files are included with this submittal, which reflect the change in stack height as well as a revised stack diameter of five inches.

Bullet Item #5: DEQ requests that the exhaust parameters—specifically the stack exit temperatures and volumetric flow rates--for the thermal conversion unit/boiler/scrubber stack be provided in the application materials for each set of operating conditions for the source. A simple scaling of operating capacity to the exhaust flow rate does not appear to apply.

A detailed description of the effects of varying the short-term processing rate of used tires, as municipal solid waste feedstock, versus the typical refuse feedstock of municipal solid waste, from the baseline of no tires processed up to the maximum requested allowable short term rate of used tires, is requested. If Dynamis has determined that the type of materials gasified in the

thermal conversion unit chambers has no effect on exhaust parameters and potential emission rates, please provide an explanation. Any effects caused by fuel variability must be represented in the significant and cumulative impact analyses. Averaging the daily throughput of a material that causes high emissions is not representative of potential to emit for the short term one hour average National Ambient Air Quality Standards (NAAQS), unless the constraint is noted. The issued permit will reflect the modeled emissions rates used in the impact analyses.

In the event the worst-case emission scenario and exhaust parameter scenario has been modeled, a detailed description of how the worst-case conditions were determined is still needed. Supporting calculations and assumptions need to be included.

The 'baseline' emissions estimate provided in the PTE calculations is representative of a mixed waste stream of both tires and MSW as described below; DEQ's statement of '*the baseline of no tires*', stated above, is inaccurate. Waste batches loaded into the primary chambers will consist of a mixture of MSW and tires; burns may consist of MSW only, but there will be no waste batches that consist 100% of tires. The maximum percentage of tires that can be processed, based on system design and fuel heating value, is 15%. Emissions factors for the thermal conversion unit were developed using source test data from test burns conducted on municipal solid waste (MSW), tires, and combined municipal solid waste and tire feedstocks. The table below shows the number of tests for each type of feedstock for criteria pollutants and TAPs.

Pollutant	**# of Tire Burn Source Tests**	**# of MSW Burn Source Tests**	**# of Combined MSW/Tire Burn Source Tests**
CO2	3	2	1
NOx	3	2	1
PM	2	2	1
HCl	2	2	1
Metals	2	2	1
Dioxin/Furan	1	2	1
SO2	2	1	0
CO	2	1	0
Ash	2	2	1

Data from a total of six test burns was used to develop the emissions factors; the average of the six test burns was calculated giving each of the source tests equal weighting. With the exception of dioxin/furan data, the number of tire burn source tests was equal to or greater than the number of MSW source tests. Because emission factors were developed using at least an equal number of tire test burns as MSW test burns, with each test burn given equal weight, the emission factors developed are appropriate for a waste stream of at least 50% tires.

In addition, source test data from tire burns indicates higher emissions from tire combustion than MSW combustion for all criteria pollutants. Therefore, by developing emissions factors based on equal weighting of both MSW and tire tests burns, emissions estimates are conservative and likely higher than actual emissions from the facility will be.

Some concern has been expressed regarding SO_2 emissions from the sulfur content in tires. However, because emission factors were developed using two tire burn tests and one MSW burn, emissions of SO_2 represented in the emissions inventory and model are conservative, as the emission factor is essentially representative of a waste stream consisting of two-thirds tires and one-third MSW. However, due to design constraints, the amount of tires combusted in the Ada County facility will not exceed 15%.

Exhaust parameters for the thermal unit are based on lower heating value, moisture content, and non-combustible content of the fuel source. The Ada county WTE facility has been designed to operate safely at a maximum peak flow condition of 570,000 lbm/hr. There are two types of conditions that will create this maximum system flow. Wet, moderate-energy fuel and dry, high-energy fuel will both require a large input of combustion air and will generate the highest flow conditions. If other fuel conditions occur, then less or more fuel will be used to insure the system maintains safe, proper operation within the design range.

Wet fuel generates flows of approximately 545,000 lbm/hr of gas. Combustion air is supplied at a rate of about 485,000 lbm/hr with the remaining mass flow coming from the fuel. There will be a high percentage of water in the flue gas (~15%); this pure water vapor will remain in the flue gas that will exit the stack with an approximate flow of 151,000 acfm at 125F. Dry fuel generates flows of approximately 569,000 lbm/hr of gas. Combustion air is supplied at a rate of about 518,000 lbm/hr with the remaining mass flow coming from the fuel. The flue gas exiting the stack will have a low percentage of water (~10%) but increased dry gas so the resulting stack flow volume will be still be approximately 151,000 acfm at 125F.

Off peak flow conditions are significantly lower than peak conditions so the system has been designed such that portions of the system are isolated to improve gas flow and system efficiency. Gas flow during off peak is only required to maintain 60,000 lb/hr of steam from the heat recovery steam generator (HRSG) to the turbine. Primary chambers that have fuel still remaining at the end of the peak period will provide gas flow during off peak operation. Primary chambers with fuel remaining will be combined with combustion air and will generate approximately 127,000lbm/hr. Combustion air is supplied at approximately 112,000 lbm/hr with the remaining mass flow from the fuel. Due to the fact that the scrubber is designed for approximately five times this flow, the gas can be scrubbed very efficiently and exhausted at a range of temperatures and moisture content. The set point for typical operation exhausts the gas at a volume flow of approximately 39,100 acfm at 135 F. For further description on the design and

operation of the system, please see the system mass balance description included as Attachment 1.

During review of exhaust parameters and facility design conditions, it was determined that the thermal unit/scrubber exhaust flows and temperatures should be adjusted to allow the unit to operate with increased efficiency. Based on revised optimization of the system, the following exhaust parameters have been updated in the emissions calculations (where applicable) and all modeling has been revised:

Thermal Unit Peak Operation:
Exhaust flow rate: 150,865 acfm
Exhaust temperature: 125.4 F

Thermal Unit Off-Peak Operation:
Exhaust flow rate: 39,100 acfm
Exhaust temperature: 134.5 F

A revised control guarantee including the above listed flow rates and temperatures, from the scrubber manufacturer, Direct Contact LLC, is included as Attachment 2.

Bullet Item #6: Please submit the AERMAP files for the project to allow DEQ to verify the extent of terrain used to generate the hill height scales for the modeling domain.

Revised AERMAP files for all receptors are included with this submittal. As described in the modeling report, receptors along the facility fenceline and roadway were manually revised per the site grading plan.

Bullet Item #7: Hour of day operational factors were applied to the NO_2 annual, SO_2 annual, and $PM_{2.5}$ annual average modeled emission rates. The hour-of-day operating factors on the thermal conversion unit stack, in combination with the reduced emission rates for the annual ambient impacts scenario, appear to represent emissions below the project's requested potential to emit. Refer to the pollutant IDs "NO2ANN", "SO2ANN", and "PM2.5ANN." Multiplying the hourly emission rates by the operating schedule provides annual emissions below the levels listed in Table 1 of the application's modeling report. These conclusions were based on the May 1, 2012 submittal for the annual modeling scenarios.

The annual modeling analyses included with this submittal were revised to reflect the project's requested PTE for annual NO_2, annual SO_2 and annual $PM_{2.5}$. The maximum lb/hr emission rate requested for both the peak and off-peak operation of the thermal unit were used in combination with the hour of day operating factor option in AERMOD.

Bullet Item #8: Areas of steep terrain should be covered with more densely-spaced discrete receptors where significant ambient impacts are predicted to occur. Note: If DEQ performs

verification modeling with a tighter receptor grid, the results must demonstrate compliance with the NAAQS.

(No response)

Bullet Item #9: Are startup and shut down emissions higher than have been proposed for normal steady-state operation during peak and off-peak operations? If so, startup and shut down emissions during peak and off-peak operations need to be accounted for in the modeling analysis as well as in the Potential to Emit calculations.

After initial startup, the system will only be shutdown/restarted for occasional maintenance. Startup procedures include pre-heating of the secondary chamber. During startup, the secondary chamber and ducting downstream must be purged to remove any un-combusted gases. The un-combusted gases will be of the same composition as the syngas that is combusted during normal operations, therefore purging emissions are expected to be equivalent emission during normal peak operation. The turbulent air blowers and induced draft fans must run at 100% flow (150,000 scfm) for a minimum of 2 minutes. This airflow provides five air exchanges within the secondary chamber, boiler, scrubber and ducting. These air exchanges insure only ambient air is present in these chambers prior to ignition and prevents potential flare or explosion conditions. After the purge sequence has been completed secondary chamber preheating can occur.

Secondary chamber pre-heating is accomplished with natural gas burners. Each burner is equipped with its own combustion air supply so turbulent air blowers are turned off and the induced draft fans slowed to prevent excess cooling of the chamber. Secondary combustion chamber burners are fired in sequence starting with the burners closest to the turbulent air inlet until each section of the chamber reaches at least 1800F. The fully combusted natural gas exhaust travels down the length of the secondary chamber pre-heating the next section, boiler and scrubber. A significant amount of the heat exiting the secondary chamber is transferred into the boiler water so very little heat is wasted during this pre-heat process. The total pre-heat cycle time will vary depending on the startup conditions. A “cold start,” such as during plant commissioning will take longer than a “warm start,” such as when the chambers have not cooled to ambient conditions. After proper secondary preheating is complete, primary chamber ignition can occur. The maximum natural gas usage expected during secondary chamber pre-heating is approximately 112,000 scf/day; which is the amount of natural gas included in the PTE calculation previously submitted to DEQ. The PTE calculation assumes the natural gas usage to occur concurrently with Thermal Unit operation.

Each primary chamber is purged sequentially with ambient air (~6000 scfm) for a minimum of 2 minutes prior to ignition to remove possible combustible gases. This purge air travels through the primary chambers and into the secondary chamber to insure any gases are combusted in the secondary chamber prior to entry to the boiler,

scrubber and exhausted to the stack. After proper purging of a primary chamber has occurred the burners are fired and run until no oxygen is measured exiting the primary chamber. When 0% O2 is measured, the gas exiting the primary chamber is considered "syn-gas" and full system operation can begin.

Syn-gas is slowly added to the secondary combustion chamber and properly combusted with the addition of turbulent air. With proper addition of syn-gas to the secondary combustion chamber the secondary burners can be turned off and the retained heat of the chamber walls cause auto combustion of the syn-gas. Syn-gas and turbulent air are steadily increased until all required primary chambers are in full syn-gas production and sufficient heat is being generated to produce electric power from the turbine. Both syn-gas and airflow are throttled to maintain a specified production of steam from the boiler to the turbine to generate the required MW's to the power grid.

Emissions during startup will consist of emissions from natural gas combustion and purging of un-combusted syngas; combustion of MSW will not occur until the primary chambers are fully pre-heated and operating and normal conditions, therefore startup emissions will not exceed the requested PTE emissions. During shutdown, MSW in the primary chambers and syngas in the secondary chambers will be allowed to combust and will exhaust under conditions similar to the off-peak operation of the Thermal Unit. Therefore, shutdown emissions are not expected to exceed the requested PTE emissions.

In addition to the responses above, JBR is also submitting a revised emissions inventory (Attachment 3). The scrubber manufacturer guarantees 41% control of $PM_{2.5}$ and smaller, with higher control efficiency expected for larger particulates. Metals emissions (with the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. The revised emissions inventory reflects updated metals emissions estimates to include a conservative 20% control of particulate metals. A revised Modeling Report is also included with this submittal.

Sincerely,

S. Manoulian

Shannon Manoulian, P.E.

Enclosures

Cc: Dynamis Energy, LLC

ATTACHMENT 1

System Mass Balance

Dynamis Energy, LLC Ada County WTE-System Mass Balance

The exact mass flow balance through the Ada county WTE system was calculated using a proprietary modeling program developed by Christopher Durand, PE and Dynamis Energy, LLC. The specific numbers and equations used in this program are intellectual property and not available for general distribution. The general methodology and final values are available for distribution and have been included.

The MSW is analyzed to determine the estimated low heating value (LHV), moisture content, and incombustible (metal, glass, dirt)/ash component. Typical MSW in the United States, within Idaho and Ada county has a LHV between 5000 and 7000 btu/lbm. Moisture content ranges from 25-40% depending on the source and environmental conditions and incombustibles account for 10-20% of the total MSW mass. The values determined from the MSW analysis are then combined with similar well-documented and published values for tires and compressed natural gas (CNG). A total LHV, moisture content and incombustible component are calculated from these combined material sources and are referred to as the "fuel source." After the fuel source composition has been determined the amount of dry air required for stoichiometric combustion (100% O2 consumption) is calculated. An amount of excess dry air required to insure complete combustion of unexpected components and provide approximately 5-7% extra oxygen exiting the stack is then calculated. The Dynamis Energy, LLC system utilizes relatively low values of excess air due the proprietary mixing process used during combustion. Typical excess air values are only 40-60% above stoichiometric requirements compared to 100-200% used by other processes. The two dry air components are added and the total amount of additional water due to relative humidity is calculated. The total combustion mass flow is calculated by adding these values to the mass of the incoming fuel. Once an air to fuel ratio has been estimated the temperature of combustion is calculated to verify proper heating of the system will occur. If the combustion temperature exceeds the desired temperature (2000F) additional air is added to cool the combustion gas and the rate of fuel supplied is maintained. If the combustion temperature is below the desired temperature then excess air is reduced (maintaining a minimum excess oxygen level of 5%). Multiple iterations of this process are carried out to converge on the optimal fuel to air ratio for the specified fuel composition. After combustion has occurred and heat has been transferred from the flue gas to the heat recovery steam generator (HRSG) the flue gas undergoes final cooling in the wet scrubber. The scrubber may add or remove pure water to the flue gas depending on the gas composition in order to optimize the cleaning of the flue gas. This last stage results in a very consistent mass flow and temperature exiting the scrubber and stack.

The Ada county WTE facility has been designed to operate safely at a maximum peak flow condition of 570,000 lbm/hr. There are two types of conditions that will create this maximum system flow. Wet, moderate-energy fuel and dry, high-energy fuel will both require a large input of combustion air and will generate the highest flow conditions. If other fuel conditions occur, then less or more fuel will be used to insure the system maintains safe, proper operation within the design range.

Wet fuel with a LHV of 6,600 btu/lbm, 45% moisture, and 20% incombustibles (10% ash, 10% other by weight) generates flows of approximately 545,000 lbm/hr of gas (472,000 lbm/hr dry gas and 73,000 lbm/hr of water vapor). Combustion air is supplied at a rate of about 485,000 lbm/hr with the remaining

mass flow coming from the fuel. The high percentage of water in the flue gas (~15%) greatly improves the efficiency of the scrubbing system and presents the opportunity to reduce overall water needs. However, significant pure water vapor will still remain in the flue gas that will exit the stack with an approximate flow of 151,000 acfm at 125F.

Dry fuel with a LHV of 7,100 btu/lbm, 24% moisture and 20% incombustibles (10% ash, 10% other by weight) generates flows of approximately 569,000 lbm/hr of gas (517,000 lbm/hr dry gas and 51,000 lbm/hr of water vapor). Combustion air is supplied at a rate of about 518,000 lbm/hr with the remaining mass flow coming from the fuel. The high heating content of the fuel reduces the total fuel required to power the turbine thus increasing the overall system efficiency. The flue gas exiting the stack will have a low percentage of water (~10%) but increased dry gas so the resulting stack flow volume will be still be ~151,000 acfm at 125F.

Off peak flow conditions are significantly lower than peak conditions so the system has been designed such that portions of the system are isolated to improve gas flow and system efficiency. Gas flow during off peak is only required to maintain 60,000 lb/hr of steam from the HRSG to the turbine. Primary chambers that have fuel still remaining at the end of the peak period will provide gas flow during off peak operation. These chambers combined with combustion air will generate approximately 127,000lbm/hr (110,000 lbm/hr dry gas and 17,000lbm/hr water vapor). Combustion air is supplied at approximately 112,000 lbm/hr with the remaining mass flow from the fuel. Due to that the scrubber is designed for approximately five times this flow, the gas can be scrubbed very efficiently and exhausted at a range of temperatures and moisture content. The set point for typical operation exhausts the gas at a volume flow of ~ 39,000 acfm at 135F.

ATTACHMENT 2

Scrubber Manufacturer Guarantee

DIRECT CONTACT LLC
P.O. Box 2969 Renton, WA 98056 ♦ Ph (425) 235-1723 ♦ Fax (425) 277-5780

June 7, 2012

Dynamis Energy, LLC
776 E. Riverside
Eagle, Idaho 83616

Attention: **Chris Durand, PE Project Engineer**

Reference: **DC062 ADA County, ID – MSW to Energy Project's Heat Recovery/pollution Abatement System**

Subject: **Equipment Supply and Engineering Proposal Revision A**

Dear Chris,

Direct Contact LLC (**DC**) appreciates the opportunity to work with Dynamis Energy LLC (**DE**) on the ADA County MSW to Energy Heat Recovery/Pollution Abatement System.

Background

DE is converting Municipal Solid Waste to Energy in ADA County, ID. The facility generates a bio-syngas via pyrolysis; the syngas is burned in a boiler to produce steam with the steam used to spin a turbine and generate electric power.

The steam exhausting the turbine is condensed and returned to the boiler. The condensate leaving the condenser needs to be heated substantially before returning to the boiler.

The syngas includes some entrained particulates, with a small fraction of acid gases (hydrochloric acid and sulfur dioxide).

DC has the technology and experience to capture a great deal of the waste heat leaving with the flue gas and returning its energy to the plant. In addition to recovering heat, DC can absorb a portion of the acid gases and scrub a portion of the particulates.

Design Conditions

Dynamis and Evergreen Engineering (EE) have developed three cases to be considered: 'Peak' and 'Off Peak'. These conditions are thoroughly described below. The Site Elevation is 3000-feet above sea level. The Peak condition is the design condition. The gross pollutant loading is proportional to the flue gas mass flow rate using the Peak as a basis.

Peak
Flue Gas Generated - Mass Flow Rate = 542,257.91-lb/hr
Flue Gas Stack Temperature = 350°F

Design Conditions (Continued)

Flue Gas Analysis: (Mole-fraction)

Oxygen	0.0579
Nitrogen	0.6797
Carbon Dioxide	0.1058
Argon	0.0083
Water Vapor	0.1484

Gross Pollutants

Sulfur Dioxide	40-lb/hr
Hydrochloric Acid	10-lb/hr
10 Micron & Smaller	7-lb/hr
2.5Micron & Smaller	7-lb/hr

Turbine Exhaust Condenser Condensate
Volumetric Flow = 433-gpm @105°F
Mass Flow = 215,042-lb/hr

Boiler Makeup Water
Volumetric Flow = 6-gpm @60°F
Mass Flow = 3,045 lb/hr

OFF Peak
Flue Gas Generated - Mass Flow Rate = 127,350.73-lb/hr
Flue Gas Stack Temperature = 350°F (assumed)

Flue Gas Analysis: (Mole-fraction)

Oxygen	0.0573
Nitrogen	0.6889
Carbon Dioxide	0.1068
Argon	0.0084
Water Vapor	0.1386

Gross Pollutants

Sulfur Dioxide	9.4-lb/hr
Hydrochloric Acid	2.3-lb/hr
10 Micron & Smaller	1.6-lb/hr
2.5Micron & Smaller	1.6-lb/hr

Turbine Exhaust Condenser Condensate

ENERGY EFFICIENCY ENVIRONMENT

Design Conditions (Continued)
Gross Pollutants (Continued)
Volumetric Flow = 100-gpm @105°F
Mass Flow = 50,000-lb/hr

Boiler Makeup Water
Volumetric Flow = 1.7-gpm @60°F
Mass Flow = 856-lb/hr

Scope
DC will provide equipment for a 'heat recovery/pollution abatement system' (HRPAS) that will use the exhaust flue gas as a heat source to add thermal energy to the condensate and boiler makeup water feeding the DA tank. The HRPAS will remove acid gases and particulates from the flue gas. Caustic soda will need to be added to the HRPAS to neutralize hydrolysis products generated or the absorption of acid gases will be limited. Water must be added to the HRPAS. The HRPAS will be a net evaporator of water and liquid water blow down will be necessary to purge salts generated in the hydrolysis of acid gases and the solid particulates scrubbed from the flue gas. The boiler blow down is directed through the vessels (V-01 and V-02) which should be enough water to adequately maintain salt concentrations in the contact water to a point that viscosity and surface tension does not affect mass transfer coefficients adversely. The method of achieving this heat recovery is described below. Please use the process flow diagrams D062-F-01A, -F-01B & -F-01C (for Peak (Design), and Off Peak Conditions respectively) and the Piping & Instrumentation Diagram provided (drawings D062-F03 through F-05) as well as the General Arrangement drawings (D062-G-01 & G-02) to help with the process description.

DC's HRPAS will consist of several unit operations, duct & piping systems, instrumentation with control logic & interlocks performed in a PLC with a HMI. The system will be transparent to the operation of the Boiler.

The project scope for DC is broken into two categories: Engineering and Equipment Supply. Using the process flow diagram as a reference, the scope breaks down as follows:

Component Description	Engineering Responsibility	Equipment Supply
Inlet Gas Duct	DC	Others
HA-01	DC	DC
HA-01's Associated Components Duct and Plenum with wash headers	DC	Others
HX-01	DC	DC
HX-02	DC	Others
F-01 & F-02 Induction Fan &	DC	DC

4160-VAC motors		
V-01 & V-02 HRPA	DC	DC
Interconnecting Duct between V-01& V-02 Stack	DC	Others
Pump P-01	DC	Others
Pumps P-02, P-03 & P-04	DC	DC
Valves: All shown on P&I Ds	DC	DC
Piping System inside target shown on P& I Ds	DC	DC
Stack	DC	Others
S-01 Filtration Equipment	Others	Others
All HRPAS Associated Supports and Platforms, Hand Rails & Ladders &/or Stairs	DC	Others
All Concrete Foundation and below grade systems	Others	Others
Electrical: All motor control and Variable Speed driver and lighting Conduit routing	Others	Others
Controls and Instrument (including modulated control valves) Package including PCL and HMI	DC	Others
CEMS Flow and Opacity Meters	Others	Others

Gas Flow

Syngas is generated in pyrolysis modules, then combusted in a second combustion unit (by-others). The very hot flue gas passes through a diversion stack (by-others). The flue gas then passes through a boiler with an economizer (by-others). The cooled flue gas leaves the economizer passes through a duct which directs the flue gas to the HRPAS. The flue gas first flows into transition TR-01 where it is evenly distributed, then passes through the washdown header and then enters the indirect heating coil (HA-01), which heats condensate while cooling the exhaust gas. The gas is only cooled to within 30°F or 40°F of its dew point; hence, although very cool, there is no concern of condensation occurring in normal operation. Downstream of HA-01, there is an exhaust wash water separation plenum, which splits the gas flow into two equal streams which are drawn into the induction Fans (F-01 and F-02). From the fans, the exhaust gas passes into two (2) [12.5 ft diameter x 33 ft straight wall with their major axis vertical] DCLLC Hydrothermal Recovery Vessels, (V-01 and V-02).

These vessels are of a special design as not only do they recover heat but they also absorb acid gases & remove particulates. First the flue gas is saturated and adiabatically cooled before entering the gas absorption section of the vessel. Then it passes to the heat recovery section of the vessel and the gas is further cooled before entering the scrubbing section where solid particulate is combined (via impaction and interception) in a coalescing mesh pad that captures solid material within liquid droplets. Most of these droplets are entrained in the gas flow leaving the coalescing mesh pad but captured in the mist elimination mesh pad above. The flue gas leaving the vessel is saturated with most of the acid gases and particulate removed. This cool saturated and relatively clean flue gas from each vessel recombines in the stack and is discharged to atmosphere. As the flue gas flows out the stack, it is monitored for effluent conditions (CEMS, flow and opacity meters are beyond the scope of DC).

Liquid Flow

The heat recovery system heats both turbine condensate (softened water - SW) and reverse osmosis water (RO - boiler feed water). Contact water (named because it is in direct contact with the exhaust gas) is a third flow stream that is part of the system. The contact water (CW) is initially made up of DI water, but as described above, water vapor generated in the combustion of syngas that drives the turbine, condenses in the vessels becoming a major constituent of CW. The contact water will have sodium hydroxide added to maintain a specific pH, approximately 10.5. The acid gas will absorb into the contact water and hydrolyze. The formation of sodium chloride and sodium sulfite will occur as well as sodium carbonate. Although makeup water (boiler blow down) will vaporize and leave with the flue gas, most of the makeup will flow out of the system purging the salts.

Contact water is circulated around & through the DCLLC Hydrothermal Recovery Vessels. The level of contact water in each vessel's reservoir is equalized using a 10" diameter line between vessels which maintains a common level in both vessels. One vessel has a 'common' overflow and the other vessel has a common reservoir level sensor. The two (2) circulation pumps draw water from both vessels via the equalization line. While either P-02 or P-03 can draw and circulate contact water to either vessel at off peak conditions, at normal flow conditions both pumps operate together. A portion of the contact water is circulated directly to the lower spray headers on the vessels absorption section. The remainder of the circulated contact water passes through a plate & frame heat exchanger (HX-01), cooling the contact water and heating condensate. The cooled contact water is again split: a portion going directly to the spray header on the heat recovery section on the vessels, and the remainder going to the filtering (S-01) system. The filtering system (by others) removes most of the collected particulates. The filtered contact water is used to wash the mist eliminator mesh pad & periodically washing the coalescing mesh pad with its waste stream being directed to the cooling tower (piping, etc is beyond the scope of this offering) . The coalescing mesh pad wash cycle is initiated on high differential pressure across the coalescing mesh pad.

Equipment Details

The heat recovery vessels are designed for non-pressurized service. The vessel's internals will be accessible via standard manways. The vessel shell is to have 1.5-inches of field-installed insulation covered with aluminum sheathing (insulation and sheathing is considered part of the installation service installed in the field by others and is outside the scope of this equipment proposal). All ductwork upstream of HA-01 is carbon steel (between HA-01 & F-01 it is stainless steel). All materials downstream & including the fan's casings & wheels are stainless steel. All piping material for RO water and contact water are stainless steel while softened water piping is carbon steel.

A skid will be located in the vicinity of the heat recovery vessels. The proposed skid system includes: one (1) 50-HP circulating water pump (P-02), one (1) 50-HP circulating water pump (P-03), with associated inlet & outlet piping. It is recommended a plate & frame heat exchanger (HX-01) be located indoors or be insulated completely. The contact lines running between V-01 & V-02 and the skid will be supplied be others.

The boiler makeup water heater HX-02 its condensate circulation pump P-01 are a part of the heat recovery system, but remote to the vessel's and skid. All items associated with boiler makeup heating will be supplied by others. DC will have process design responsibility, but piping design for freeze protection and maintenance accessibility is the responsibility of others.

The contact water in the reservoir of the vessels is maintained at a pH of 10.5 to 11. This is achieved by continuous sampling the pH of contact water exiting the circulation pumps and adding sodium hydroxide solution at P-02 and P-03 suction. The sodium hydroxide solution is presumed at a concentration of 50% water. Others will provide insulated/heat traced piping between the sodium hydroxide storage tank (by others) and the metering pump (P-04). P-04 and the pH sensor will be mounted on the DC skid. The pH sensor will be supplied by others and the pump will be supplied by DC.

The instrumentation & controls process design will be by DC. DC will generate a process description & loop list so the customer's PLC integrator/provider can specify, design & program the PLC. The Motor Control Center and Control Panel, PLC and HMI will be designed and supplied by others. The electrical equipment shall include motor starters for the pumps (P-01 (1-Hp motor @ 460-VAC), P-02 (50-Hp motor @ 460-VAC), & P-03 (50-Hp motor @ 460-VAC)) and variable speed drives for the fans (F-01 (400-Hp motor @ 4160-VAC) & F-02 (400Hp motor @ 4160-VAC)) & metering pump P-04 (.333-Hp motor @ 460-VAC). Others will provide a control panel will include an RS View HMI providing supervisory & process control with the associated PLC (AB Contrologix) and DC will assist in theses efforts. The location of loop tuning will be decided by the provider.

Power distribution and local disconnects will be supplied (by others) for field distribution to the six (6) usage points: the pumps P-01, P-02, P-03 and P-04 at 480 VAC, the induced draft fans F-01 & F-02 (both of which are 400 HP) at 4160-VAC and 120-volt single phase transformer (30 amps) to be field routed to the control panel.

Process Engineering:

DCLLC will select, size or specify all components shown on the flow diagram with the exception of the filtration system.

Mechanical Engineering:

DCLLC will design / layout all equipment components with the exception of the filtration system and the remote skid for HX-02 & P-01.

Specific Exclusions

- *Electrical:* Supply of specified power requirements to the customer's Motor Control Center (MCC) with its associated motor starters/VFDs for P-01, P-02, P-03, P-04, F-01 & F-02 and from there to the motors, local controls and monitoring instrumentation is by others. All power wiring, conduit, tray, etc. and installation of same is by others.
- *Controls:* Supply of the PLC, HMI, any local control panels and all local instrumentation is by others. All control wiring & conduit as well as all installation of same is by others.
- *Foundation:* Design & supply of the foundation(s) required for the heat recovery vessels, equipment skid(s), etc are by others.
- *Structural:* All structural supports other than the unitary skid underneath the pump/heat exchanger module are by others. This includes vessel access ladders & platforms.
- *Mechanical:* Field items required as part of a complete installation will include the following items by others:
    - Insulated pipe lines used for supply and return hot condensate. The design requires isolation & check valves at the loop connection points, which are to be supplied by the installing contractor.
    - Insulation of V-01 & V-02 (described earlier).
    - Insulated pipe lines used for cool supply and hot return RO water. The design requires isolation & check valves at the connection points to the makeup supply & these are to be included by the installing contractor.
    - Drain/overflow lines from V-01 & V-02 to a client-specified sewer connection.
    - Design & supply of the S-01 Filtration system for contact water with the associated interconnecting piping, vales, etc.
    - Supply of the P-01, HX-02 and all interconnecting piping & valving, etc.
    - Low-pressure flue gas inlet ducting for:
        - 1) hot flue gas from the economizer to DCLLC system inlet (with insulation),
        - 2) Cool flue gas from the V-01 & V-02 discharge to atmosphere (via the stack).
- *Permits:* All required permits (building, etc.) are specifically outside the scope of this proposal and to be provided by the client.

Utility Requirements

- Makeup water (RO) must have sufficient pressure to overcome 12-psi across the DCLLC system.
- RO & Softened Water must have sufficient pressure to overcome 20-psi across the DCLLC system's piping & heat exchangers.
- Electrical power (see scope): Transfer Pump P-01: 1-HP, Circulation Pump P-02: 50 HP, Circulation Pump P-03: 50-HP: Sodium Hydroxide Pump P-04: 1/3 HP, Induced Draft Fans F-01 & F-02: 400 HP each.
- Clean (low volume), dry air (90-psig) for pneumatic actuation for control dampers and valves.

Summary of Conditionally Guaranteed Emissions to Atmosphere with operational notes:

Peak Load:

Heat Recovery	31.00-Million BTU/hr
Stack Exhaust Flow	150,865-ACFM @ 125.4°F

Pollutant Reductions

Sulfur Dioxide	71.25%
Hydrochloric Acid	94.0%
2.5 Micron Particle & Small	41.0%

Off Peak:

Heat Recovery	8.43-Million BTU/hr
Stack Exhaust Flow	39,100-ACFM @ 134.5°F

Pollutant Reductions

Sulfur Dioxide	71.25%
Hydrochloric Acid	94.0%
2.5 Micron Particle & Small	41.0%

We have assumed: that the constituents, noted above, exist proportionally to the mass flow of flue gas leaving the boiler and that the particulate material in the flue gas is generally a solid material, and is not gelatinous or tacky. DCLLC conditionally guaranteed the above reductions based on flows up to the 'Peak Loading" conditions, given the earlier assumptions.

ENERGY EFFICIENCY ENVIRONMENT

Corrosion Guarantee:
All stainless steel non-rotating components are guaranteed for a period of two years from the date of startup or 30 months from date of delivery, whichever is shortest, based on the attached customer provided flue gas chemistry. This guarantee is applicable should significant evidence of corrosion appear while performing its intended purpose. DCLLC will repair or replace these items including parts and labor. The repair and or replacement of the items are the sole remedy provided in this Corrosion Guarantee. All repaired or replaced parts will have the balance of the initial warranty period remaining. All rotating equipment will be limited to the manufacturer's Corrosion Guarantee language, which will be provided upon final selection.

Direct Contact LLC is uniquely qualified to provide our patented equipment designs and complete engineering and project oversight experience as proven at other operations. I look forward to furthering this discussion as soon as your schedule allows. Should you have any questions, please don't hesitate to contact my office.

Thank you for your interest and continued consideration of **Direct Contact LLC.** We look forward to working with you and your colleagues on a project that will enable you to maximize the energy efficiency of the customer's operation.

With *Warmest* Regards,

Bill Carson
Chief Engineer
Direct Contact LLC

Cc: Curt Rothman (DCLLC)
Jim Shields (DCLLC)

ENERGY EFFICIENCY ENVIRONMENT

ATTACHMENT 3

Emissions Inventory

Dynamis Energy, LLC
Pilot WTE Facility

FACILITY POTENTIAL TO EMIT - CRITERIA POLLUTANTS

	Criteria Pollutants											
	NOx Emissions		CO Emissions		PM-10/PM-2.5 Emissions		SOx Emissions		VOC Emissions		Lead Emissions	
Description	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Thermal Conversion Unit - Peak	29.93	87 38	10.90	31.83	3.66	10.68	8.54	24.94			0 03	0.09
Thermal Conversion Unit - OffPeak	4.41	6.44	1 61	0.54	0.54	0.79	1.26	1 84			0.00	0.01
Cooling Tower					0.02	0.08						
Ash System					0.45	1.97					5.10E-04	2.23E-03
Emergency Generator	1.30	0.33	0 26	0.07	0.03	0.01	0.98	0 25	1.19	0.30		
Ignition Systems	0.47	2.04	0 39	1.72	0.02	0.09	0.00	0 00	0.03	0.11	2.33E-06	1.02E-05
Total	**36.104**	**96.188**	**13.164**	**34.149**	**4.720**	**13.616**	**10.786**	**27.030**	**1.211**	**0.409**	**0.0358**	**0.099**

FACILITY POTENTIAL TO EMIT - TAPS

NON-CARCINOGENS (POUNDS PER HOUR)						
Pollutant	CAS #	TAP Emissions - Max (lb/hr)	TAP Emissions - Average (lb/hr)	TAP Emissions (tpy)	Screening Level (lb/hr)	Modeling? (Y/N)
Acrolein	107-02-8	1.13E-04	1.13E-04	2.82E-05	1.70E-02	No
Aluminum	7429-90-5	1.05E-01	1.02E-01	4.48E-01	6 67E-01	No
Antimony	7440-36-0	7.86E-04	5.63E-04	2.46E-03	3 30E-02	No
Barium	7440-39-3	7.92E-04	7.32E-04	3.21E-03	3 30E-02	No
Chromium	7440-47-3	1.85E-03	1.35E-03	5.92E-03	3 30E-02	No
Cobalt	7440-48-4	1.71E-03	1.62E-03	7.09E-03	3 30E-03	No
Copper	7440-50-8	1.12E-03	9.08E-04	3.98E-03	6.70E-02	No
Fluoride (as F) (Hydrogen Fl)	16984-48-8	2.84E-03	2.03E-03	8.91E-03	1 67E-01	No
Hexane	110-54-3	8.40E-03	8.40E-03	3.68E-02	1.20E+01	No
Hydrogen Chloride	7647-01-0	5.95E-01	5.95E-01	2 61E+00	5 00E-02	See Footnote 1
Manganese	7439-96-5	6.96E-03	5.23E-03	2.29E-02	3 33E-01	No
Mercury*	7439-97-6	3.10E-03	2.22E-03	9.72E-03	N/A	*
Molybdenum	7439-98-7	2.24E-03	1.61E-03	7.06E-03	3 33E-01	No
Naphthalene**	91-20-3	3.04E-06	3.04E-06	1 25E-05	9.10E-05	No
Pentane	109-66-0	1.21E-02	1.21E-02	5.31E-02	1.18E+02	No
Phosphorous	7723-14-0	2.66E-03	2.66E-03	1.17E-02	7 00E-03	No
Selenium	7782-49-2	2.22E-03	1.59E-03	6.95E-03	1 30E-02	No
Silver	7440-22-4	2.92E-07	2.92E-07	1.28E-06	7 00E-03	No
Toluene	108-88-3	5.15E-04	5.15E-04	1 94E-04	2.50E+01	No
o-Xylene	1330-20-7	3.48E-04	3.48E-04	8.70E-05	2.90E+01	No
Zinc	7440-66-6	3.42E-01	3.09E-01	1 35E+00	6 67E-01	No

*Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215.

**Although listed as a noncarcinogen in the Rules, DEQ has determined that naphthalene is a possible/probable carcinogen. Compliance for naphthalene emissions should be based on the EL or AACC listed in Section 586 for PAH.
1. Regulated under NSPS Subpart Eb, excluded from modeling under IDAPA 58 01.01 210.20.

CARCINOGENS (POUNDS PER HOUR)						
Pollutant	CAS #	TAP Emissions - Max (lb/hr)	TAP Emissions - Average (lb/hr)	TAP Emissions (tpy)	Screening Level (lb/hr)	Modeling? (Y/N)
Acetaldehyde	75-07-0	9.37E-04	9.37E-04	5.35E-05	3 00E-03	No
Arsenic	7440-38-2	7.46E-07	7.46E-07	3.27E-06	1 50E-06	No
Benzene	71-43-2	1.15E-03	1.15E-03	3 28E-04	8.00E-04	Yes
Beryllium	7440-41-7	4.48E-08	4.48E-08	1.96E-07	2.80E-05	No
Cadmium	7440-43-9	3.48E-03	2.50E-03	1.09E-02	3.70E-06	See Footnote 1
Dioxin/Furan	1746-01-6	1.35E-06	9.65E-07	4.23E-06	1.50E-10	See Footnote 1
Formaldehyde	50-00-0	1.79E-03	1.79E-03	1 89E-03	5.10E-04	Yes
Nickel	7440-02-0	1.51E-02	8.69E-03	3 81E-02	2.70E-05	Yes
Benzo(a)pyrene	50-32-8	5.60E-09	5.60E-09	2.45E-08	2.00E-06	No
Benz(a)anthracene	56-55-3	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Benzo(b)fluoranthene	205-82-3	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Benzo(k)fluoranthene	205-99-2	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Chrysene	218-01-9	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Dibenzo(a,h)anthracene	53-70-3	5.60E-09	5.60E-09	2.45E-08	2.00E-06	No
Indeno(1,2,3-cd)pyrene	193-39-5	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Total PAHs		2.45E-07	2.45E-07	1 07E-06	9.10E-05	No

Dynamis Energy WTE Facility
Thermal Conversion System
Thermal Conversion Unit

Total MSW Throughput	367.2	tpd
Total MSW Throughput	15.30	ton/hr
Total MSW Throughput	30600	lb/hr
Peak Operating Hours	5840	hr/yr
Off-Peak Operating Hours	2920	hr/yr
Peak Exhaust Flow	150,865	acfm @ 125.4F
Off-Peak Exhaust Flow	39,100	acfm @ 134.5F

Hours	7am - 11pm	11pm-7am
Throughput (tpd)	342	25.2
Throughput (tph)	21.375	3.15
Percent of day	0.67	0.33

Pollutant Emission Factors	PM/PM10/ PM2.5 lb/ton	SO2 lb/ton	NOx lb/ton	CO lb/ton	Lead lb/ton
Thermal Conversion Unit Exhaust	0.29	1.39	1.4	0.51	1.44E-03

PM, NOx, CO, SO2, Lead Emission factor from source test averages
*SO2 Emission rate based on scrubber manufacturer guarantee of 71.25% control. PM2.5 emission rate based on scrubber manufacturere guarantee of 41%.

7am-11pm - PEAK

Pollutant	PM/PM10/PM2.5		SO_2		NOx		CO		Lead	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Thermal Conversion Unit Exhaust Uncontrolled	6.20	18.10	29.71	86.76	29.93	87.38	10.90	31.83	0.03	0.09
Thermal Conversion Unit Exhaust Controlled	3.66	10.68	8.54	24.94	29.93	87.38	10.90	31.83	0.03	0.09
Controlled Boiler Stack Emissions (Thermal Unit + Ignition System)	3.68	10.74	8.54	24.94	30.39	88.74	11.29	32.98	0.03	0.09

11pm-7am - OFF PEAK

Pollutant	PM/PM10/PM2.5		SO_2		NOx		CO		Lead	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Thermal Conversion Unit Exhaust Uncontrolled	0.91	1.33	4.38	6.39	4.41	6.44	1.61	0.54	0.00	0.01
Thermal Conversion Unit Exhaust Controlled	0.54	0.79	1.26	1.84	4.41	6.44	1.61	0.54	0.00	0.01
Controlled Boiler Stack Emissions (Thermal Unit + Ignition System)	0.56	0.82	1.26	1.84	4.88	7.12	2.00	1.11	0.00	0.01

TOXIC AIR POLLUTANTS (TAPs) CALCULATIONS

NON CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	TAP Emission Factor (lb/ton)	Peak TAP Emissions (lb/hr)	Off Peak TAP Emissions (lb/hr)	Average TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling (based on peak)? (Y/N)	Modeling (based on Average)? (Y/N)
Aluminium	7429-90-5	4.74E-04	8.11E-03	1.19E-03	5.80E-03	6.67E-01	No	No
Antimony	7440-36-0	4.60E-05	7.86E-04	1.16E-04	5.63E-04	3.30E-02	No	No
Barium	7440-39-3	1.23E-05	2.11E-04	3.10E-05	1.51E-04	3.30E-02	No	No
Chromium	7440-47-3	1.03E-04	1.76E-03	2.60E-04	1.26E-03	3.30E-02	No	No
Copper	7440-50-8	4.33E-05	7.41E-04	1.09E-04	5.30E-04	6.70E-02	No	No
Cobalt	7440-48-4	1.77E-05	3.03E-04	4.47E-05	2.17E-04	3.30E-03	No	No
Hydrogen Chloride	7647-01-0	See Note 1 Below	5.95E-01	5.95E-01	5.95E-01	5.00E-02	Mode ing not required (IDAPA 58.01.01 210.20)	
Hydrogen Flouride	NA	1.33E-04	2.84E-03	4.19E-04	2.03E-03	1.67E-01	No	No
Manganese	7439-96-5	3.56E-04	6.08E-03	8.96E-04	4.35E-03	3.33E-01	No	No
Mercury	7439-97-6	1.45E-04	3.10E-03	4.57E-04	2.22E-03	N/A	See Note 2 Below	
Molybdenum	7439-98-7	1.30E-04	2.22E-03	3.27E-04	1.59E-03	3.33E-01	No	No
Selenium	7782-49-2	1.30E-04	2.22E-03	3.27E-04	1.59E-03	1.30E-02	No	No
Zinc	7440-66-6	6.68E-03	1.14E-01	1.68E-02	8.18E-02	6.67E-01	No	No

TAPs Emission factor from source test averages.
1. HCl emission rate of 0.595 lb/hr based on baghouse manufacturer guarantee

2. Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215

The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (w th the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	TAP Emission Factor (lb/ton)	Peak TAP Emissions (lb/hr)	Off Peak TAP Emissions (lb/hr)	Average TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling (based on peak)? (Y/N)	Modeling (based on Average)? (Y/N)	Stack Emissions (Thermal Unit + Ignition System) PEAK lb/hr	PEAK tpy	OFF PEAK lb/hr	OFF PEAK tpy
Cadmium	7440-43-9	2.02E-04	3.46E-03	5.10E-04	2.48E-03	3.7E-06	Mode ing not required (IDAPA 58.01.01 210.20)					
Dioxin/Furan		6.31E-08	1.35E-06	1.99E-07	9.65E-07	1.50E-10	Mode ing not required (IDAPA 58.01.01 210.20)					
Nickel	7440-02-0	8.81E-04	1.51E-02	2.22E-03	8.63E-03	2.70E-05	Yes	Yes	1.51E-02	4.40E-02	2.23E-03	3.25E-03

TAPs Emission factor from source test averages.
The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (w th the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

Dynamis Energy WTE Facility
Thermal Conversion System - Hidden Hollow Landfill
Thermal Conversion Units - Ignition Systems HAPs

TOXIC AIR POLLUTANTS (TAPs) COMBUSTION CALCULATIONS
NATURAL GAS

Emission Unit	Fuel Usage
Primary Chamber Ignition	4,664.71 scf/hr

NON-CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	EF for NG Combustion ($lb/10^6$ scf)[a]	TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling? (Y/N)
Barium	7440-39-3	4.4E-03	1.64E-05	3.3E-02	No
Chromium	7440-47-3	1.4E-03	5 22E-06	3.3E-02	No
Cobalt	7440-48-4	8.4E-05	3.13E-07	3.3E-03	No
Copper	7440-50-8	8.5E-04	3.17E-06	6.7E-02	No
Hexane	110-54-3	1.8E+00	8.40E-03	1.2E+01	No
Manganese	7439-96-5	3.8E-04	1.42E-06	3.33E-01	No
Mercury	7439-97-6	2.6E-04	1 21E-06	N/A	See Note 1 Below
Molybdenum	7439-98-7	1.1E-03	4.10E-06	3.33E-01	No
Naphthalene*	91-20-3	6.1E-04	2 85E-06	3.33E+00	No
Pentane	109-66-0	2.6E+00	1 21E-02	1.18E+02	No
Selenium	7782-49-2	2.4E-05	8 96E-08	1.3E-02	No
Toluene	108-88-3	3.4E-03	1 59E-05	2.5E+01	No
Zinc	7440-66-6	2.9E-02	1 08E-04	6.67E-01	No

1. Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215

*Although listed as a noncarcinogen in the Rules, DEQ has determined that naphthalene is a possible/probable carcinogen. Compliance for naphthalene emissions should be based on the EL or AACC listed in Section 586 for PAH.

The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (with the exception of Mercury) from the thermal unit (including primary igni ion system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	EF for Natural Gas Combustion ($lb/10^6$ scf)[a]	TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling? (Y/N)	Peak (tpy)	Off peak (tpy)
Arsenic	7440-38-2	2.0E-04	7.46E-07	1.5E-06	No		
Benzene	71-43-2	2.1E-03	9 80E-06	8.0E-04	No	2.86E-05	1.43E-05
Beryllium	7440-41-7	1.2E-05	4.48E-08	2.8E-05	No		
Cadmium	7440-43-9	1.1E-03	4.10E-06	3.7E-06	Modeling not required (IDAPA 58 01.01 210.20)		
Formaldehyde	50-00-0	7.5E-02	3 50E-04	5.1E-04	No	1.02E-03	5.11E-04
Nickel	7440-02-0	2.1E-03	7.8E-06	2.7E-05	No	2.29E-05	1.14E-05
Benzo(a)pyrene	50-32-8	1.2E-06	5.60E-09	2.0E-06	No		
Benz(a)anthracene	56-55-3	1.8E-06	8.40E-09	NA	No		
Benzo(b)fluoranthene	205-82-3	1.8E-06	8.40E-09	NA	No		
Benzo(k)fluoranthene	205-99-2	1.8E-06	8.40E-09	NA	No		
Chrysene	218-01-9	1.8E-06	8.40E-09	NA	No		
Dibenzo(a,h)anthracene	53-70-3	1.2E-06	5.60E-09	NA	No		
Indeno(1,2,3-cd)pyrene	193-39-5	1.8E-06	8.4E-09	NA	No		
Total PAHs		1.1E-05	5 32E-08	2.00E-06	No		

[a]EFs from AP-42, Tables 1.4-3 and 1.4-4, 7/98
[b]EFs from AP-42, Table 1.3-10, 9/98

The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (with the exception of Mercury) from the thermal unit (including primary igni ion system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

IDEQ PTC Forms
Toxic Air Pollutant Emissions Inventory

Table 1. PRE- AND POST PROJECT NON-CARCINOGENIC TAP EMISSIONS SUMMARY POTENTIAL TO EMIT

Non-Carcinogenic Toxic Air Pollutants (sum of all emissions)	Pre-Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Non-Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Acrolein	0 00E+00	1 13E-04	1 13E-04	1 70E-02	No
Aluminum	0 00E+00	1 02E-01	1 02E-01	6 67E-01	No
Antimony	0 00E+00	5 63E-04	5 63E-04	3 30E-02	No
Barium	0 00E+00	7 32E-04	7 32E-04	3 30E-02	No
Chromium	0 00E+00	1 35E-03	1 35E-03	3 30E-02	No
Cobalt	0 00E+00	1 62E-03	1 62E-03	3 30E-03	No
Copper	0 00E+00	9 08E-04	9 08E-04	6 70E-02	No
Fluoride (as F) (Hydrogen Fl)	0 00E+00	2 03E-03	2 03E-03	1 67E-01	No
Hexane	0 00E+00	8 40E-03	8 40E-03	1 20E+01	No
Hydrogen Chloride	0 00E+00	5 95E-01	5 95E-01	5 00E-02	See Footnote 1
Manganese	0 00E+00	5 23E-03	5 23E-03	3 33E-01	No
Molybdenum	0 00E+00	1 61E-03	1 61E-03	3 33E-01	No
Naphthalene**	0 00E+00	3 04E-06	3 04E-06	9 10E-05	No
Pentane	0 00E+00	1 21E-02	1 21E-02	1 18E+02	No
Phosphorous	0 00E+00	2 66E-03	2 66E-03	7 00E-03	No
Selenium	0 00E+00	1 59E-03	1 59E-03	1 30E-02	No
Silver	0 00E+00	2 92E-07	2 92E-07	7 00E-03	No
Toluene	0 00E+00	5 15E-04	5 15E-04	2 50E+01	No
o-Xylene	0 00E+00	3 48E-04	3 48E-04	2 90E+01	No
Zinc	0 00E+00	3 09E-01	3 09E-01	6 67E-01	No

See spreadsheets prepared by JBR (included in Appendix F of the permit application for further information regarding emission factors and calculation assumptions.

1. Regulated under NSPS Subpart Eb, excluded from modeling under IDAPA 58.01 01 210.20.

**Although listed as a noncarcinogen in he Rules, DEQ has determined hat naphthalene is a possible/probable carcinogen. Compliance for naphthalene emissions should be based on he EL or AACC listed in Section 586 for PAH.

Table 2. PRE- AND POST PROJECT CARCINOGENIC TAP EMISSIONS SUMMARY POTENTIAL TO EMIT

Carcinogenic Toxic Air Pollutants (sum of all emissions)	Pre-Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Post Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Change in Annual Average Emissions Rates for Units at the Facility (lb/hr)	Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Acetaldehyde	0 00E+00	9 37E-04	9 37E-04	3 00E-03	No
Arsenic	0 00E+00	7 46E-07	7 46E-07	1 50E-06	No
Benzene	0 00E+00	1 15E-03	1 15E-03	8 00E-04	Yes
Beryllium	0 00E+00	4 48E-08	4 48E-08	2 80E-05	No
Cadmium	0 00E+00	2 50E-03	2 50E-03	3 70E-06	See Footnote 1
Dioxin/Furan	0 00E+00	9 65E-07	9 65E-07	1 50E-10	See Footnote 1
Formaldehyde	0 00E+00	1 79E-03	1 79E-03	5 10E-04	Yes
Nickel	0 00E+00	8 69E-03	8 69E-03	2 70E-05	Yes
Benzo(a)pyrene	0 00E+00	5 60E-09	5 60E-09	2 00E-06	No
Benz(a)anthracene	0 00E+00	8 40E-09	8 40E-09	2 00E-06	No
Benzo(b)fluoranthene	0 00E+00	8 40E-09	8 40E-09	2 00E-06	No
Benzo(k)fluoranthene	0 00E+00	8 40E-09	8 40E-09	2 00E-06	No
Chrysene	0 00E+00	8 40E-09	8 40E-09	2 00E-06	No
Dibenzo(a,h)anthracene	0 00E+00	5 60E-09	5 60E-09	2 00E-06	No
Indeno(1,2,3-cd)pyrene	0 00E+00	8 40E-09	8 40E-09	2 00E-06	No
Total PAHs	0 00E+00	2 45E-07	2 45E-07	9 10E-05	No

1. Regulated under NSPS Subpart Eb, excluded from modeling under IDAPA 58.01.01 210.20.

See spreadsheets prepared by JBR (included in Appendix F of the permit application for further information regarding emission factors and calculation assumptions.

IDEQ PTC Forms
Facility Wide Hazardous Air Pollutant Potential to Emit

Table 1 HAP POTENTIAL TO EMIT EMISSIONS SUMMARY

HAP Pollutants	PTE (T/yr)
Acrolein	4.95E-04
Antimony	2.46E-03
Chromium	5.92E-03
Cobalt	7.09E-03
Fluoride (as F) (Hydrogen Fl)	8.91E-03
Hexane	3.68E-02
Hydrogen Chloride*	2.61E+00
Manganese	2.29E-02
Mercury	9.72E-03
Naphthalene	1.33E-05
Phosphorous	1.17E-02
Selenium	6.95E-03
Toluene	2.26E-03
o-Xylene	1.52E-03
Acetaldehyde	4.10E-03
Arsenic	3.27E-06
Benzene	5.04E-03
Beryllium	1.96E-07
Cadmium	1.09E-02
Dioxin/Furan	4.23E-06
Formaldehyde	7.85E-03
Nickel	3.81E-02
Total	2.79E+00

* Maximum Individual HAP

** See spreadsheets prepared by JBR (included in Appendix F of the permit application for further information regarding emission factors and calculation assumptions.

From: Shannon Manoulian <smanoulian@jbrenv.com>
Sent: Monday, July 02, 2012 10:07 AM
To: Darrin Pampaian
Cc: Chris Durand; Pete Johnson; Mahaffey Lloyd
Subject: Dynamis Facility Permit - Tires

Hi Darrin,

In order to be consistent with other permits related to the Ada County WTE facility, Dynamis will accept a permit limit of 1.5% tires in the air quality permit.

Please let me know if you have any questions.

Thanks!
Shannon

Shannon Manoulian, P.E.
JBR Environmental Consultants, Inc.
7669 West Riverside Drive, Suite 101
Boise, ID 83714
208-853-0883 (phone)
208-853-0884 (fax)
734-624-4555 (cell)
www.jbrenv.com

From: Shannon Manoulian [mailto:smanoulian@jbrenv.com]
Sent: Monday, July 09, 2012 12:08 PM
To: Darrin Mehr
Cc: Kevin Schilling; Dave Strohm
Subject: Dynamis Energy Modeling

Hi Darrin,

Please find attached to this email, JBR's submittal describing how receptor elevations and facility ambient air boundary and source locations will be adjusted based on our modeling discussion meeting on July 3.

Do not hesitate to contact Dave or me if you have any questions or concerns.

Best Regards,
Shannon

Shannon Manoulian, P.E.
JBR Environmental Consultants, Inc.
7669 West Riverside Drive, Suite 101
Boise, ID 83714
208-853-0883 (phone)
208-853-0884 (fax)
734-624-4555 (cell)
www.jbrenv.com

Document for Certification:
Attachment: Model Discussion Issues – 070912doc.pdf (801 KB)

Model Discussion Issues – 070912doc.pdf

July 9, 2012 Submittal

creating solutions for today's environment

VIA EMAIL

July 9, 2012

Mr. Darrin Mehr
Air Quality Analyst
Idaho Department of Environmental Quality
1410 North Hilton
Boise, Idaho 83706-1255

Re: Dynamis Energy, LLC, Boise
Response to Modeling Discussion Issues – July 3, 2012

The purpose of this letter is to provide JBR's proposed path forward to rectify issues associated with the air dispersion modeling submitted to DEQ in support of the PTC application for the Dynamis Energy, LLC Ada County WTE Facility. These issues were discussed during a meeting between IDEQ and JBR on July 3, 2012, and also outlined in the document titled "Dynamis Energy Modeling Discussion Issues – July 3, 2012", prepared by IDEQ. Each issue and proposed resolution is outlined below.

Item #1: *The coordinate system used to establish elevations for receptors is not consistent with the coordinate system used for the site boundary and the base elevation.*

Property boundary and source location coordinates were provided to JBR by another consulting firm. It was indicated that the coordinates were provided in the NAD83 datum; however, upon further review and import of the modeled domain into Google Earth, it was determined that coordinates were not provided in NAD83 datum. Using Google Earth imagery and scaled site plans (as provided in the permit application), the property boundary, buildings, and sources were shifted to be consistent with the correct NAD83 locations.

In addition, the receptor network developed for the modeling analysis is based on a grid system extending outward from the property boundary. Therefore, a revised receptor grid was generated based on the revised property boundary location. Revised NED was downloaded from the USGS website, and AERMAP was re-run to

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determine receptor elevation and terrain max for the revised receptor locations.

The QUADDATE (the most recent revision date) of the NED data for the areas covering the receptor network ranges from 1999 to 2002. Based on a review of historical images in Google Earth, significant grading, road construction and topographical changes occurred at the landfill between 2002 and the present. Imagery shown in Google Earth is from 2011; however, elevations given by Google Earth appear to be consistent with the 2002 NED data elevations.

JBR will use the Dynamis site grading plan to manually adjust receptor elevations where data is available in the immediate vicinity of the Dynamis property, as shown on the plan. Updated grading information for the landfill property is not available; therefore, the NED elevations will not be adjusted for receptors outside of the extent of the Dynamis grading plan. The exception to this will be where the NED receptor elevation of a receptor adjacent to an adjusted Dynamis receptor differs by more than 25 feet. These instances will be addressed on a case-by-case basis, and the NED elevation will be adjusted in order to 'smooth' the transition between receptors. This will be done to ensure that no plume impacts are missed due to a large discrete receptor elevation change.

As shown on the grading plan, the finished floor elevation of the facility buildings, as well as the ground elevation will be 3175 feet; building and source base elevations in the model reflect this value.

Item #2: *Nickel emission rates - UNITPEAK was modeled at 1.51E-03 lb/hr; the emissions inventory spreadsheet places UNITPEAK emissions at 1.51E-02 lb/hr.*

The nickel emission rate will be corrected to be consistent with the emissions inventory. Revised model files will be submitted to IDEQ.

Item #3: *Additional modeling scenarios must be run if different levels of operation greater or less than already modeled are requested for the facility.*

Per the contract between Dynamis and Idaho Power, Dynamis will provide 22 MW of power to Idaho Power continually during peak hours (7am to 11pm). Based on system design, and estimated fuel heat value, this will be achieved by operating the system consistent with the temperatures and exhaust flow rates indicated in the modeling analysis for the UNITPEAK operation. The system will be 'turned down' between the hours of 11pm and 7am, such that it will continue to run, however, power generated during these hours will be used to power the facility. Due to the contracted power output requirements, Dynamis does not reasonably expect to operate the facility at any other level of operation greater or less than already modeled.

Item #4: *Confirm that the exhaust stack for the ash baghouse will be vertically oriented and not horizontal or equipped with a rain cap or downturned outlet and this stack will terminate at a height of 55 ft above grade.*

The exhaust stack for the ash baghouse will be fabricated by one of Dynamis' contractors. Donaldson Filtration will not manufacture the exhaust stack. Included as an attachment to this letter are two figures showing the configuration and location of the ash baghouse exhaust stack and diameter. In addition, fan curves have been provided for two fans similar to those proposed for the baghouse. The system will be operating between 12 and 16 inches WC static pressure. The blower discharge points are rectangular and have a larger area then the 1.5-foot diameter stack, so there will be a transition from rectangular to round and likely a nozzle on the stack top to accelerate the air. The stack will not be equipped with a raincap or downturned outlet. Based on the height and diameter of the stack as proposed by the Dynamis designs and attached fan curves, the exit velocities represented in the model are achievable and accurate.

Sincerely,

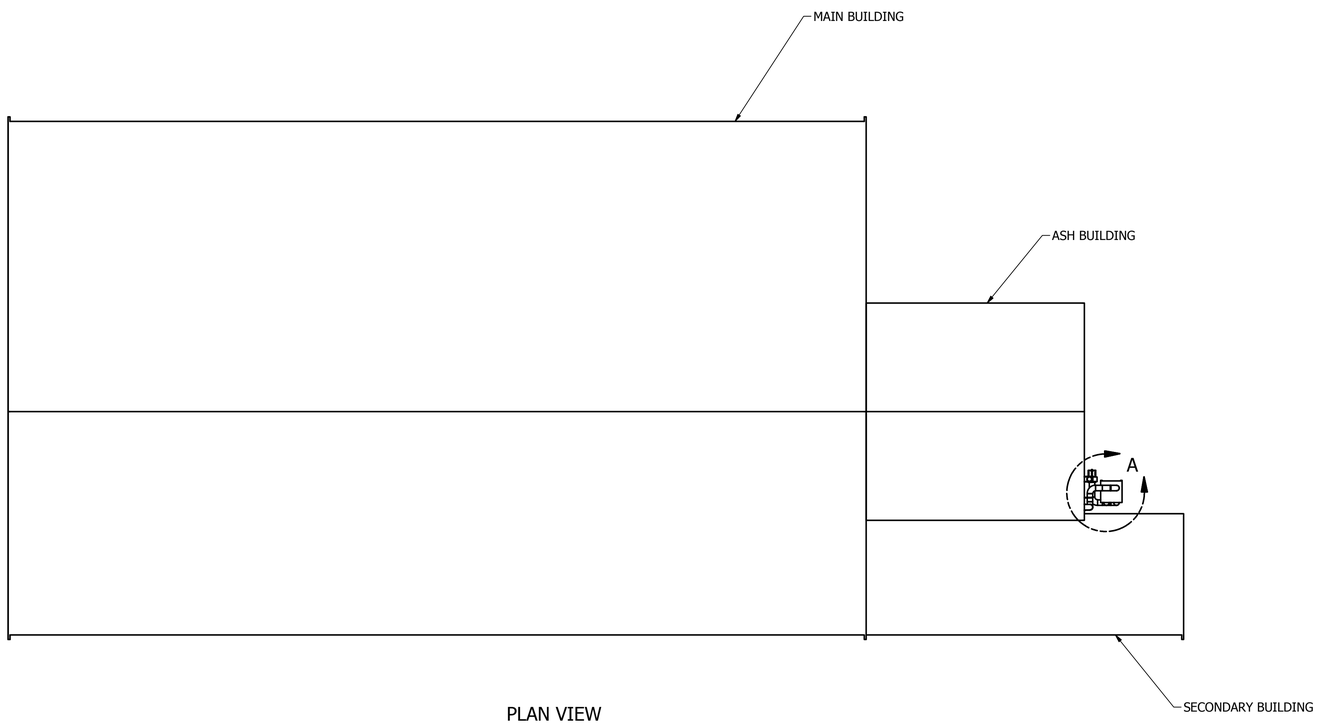
Shannon Manoulian, P.E.

Enclosures

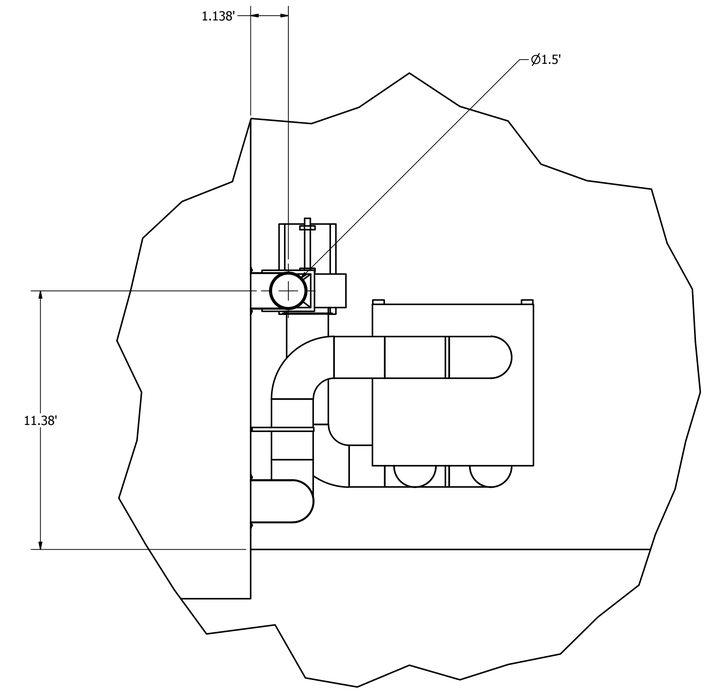
Cc: Kevin Schilling, IDEQ
David Strohm, JBR

ATTACHMENT 1

Ash System Stack and Fan Curves



PLAN VIEW



DETAIL A
SCALE 1 / 40
(ASH SYSTEM BAGHOUSE)

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES TOLERANCES ARE:		DRAWN KS	7/3/2012
DECIMAL	WELD ± 1/32	CHECKED	
.X ±.1	CHAMFERS ±5°	QA	
.XX ±.02	ANGLES ±1°	MFG	
.XXX ±.005	CAST ±1/8	APPROVED	
FRACTIONS ±1/16			
THIRD ANGLE PROJECTION		MATERIAL N/A	FINISH N/A

DYNAMIS ENERGY

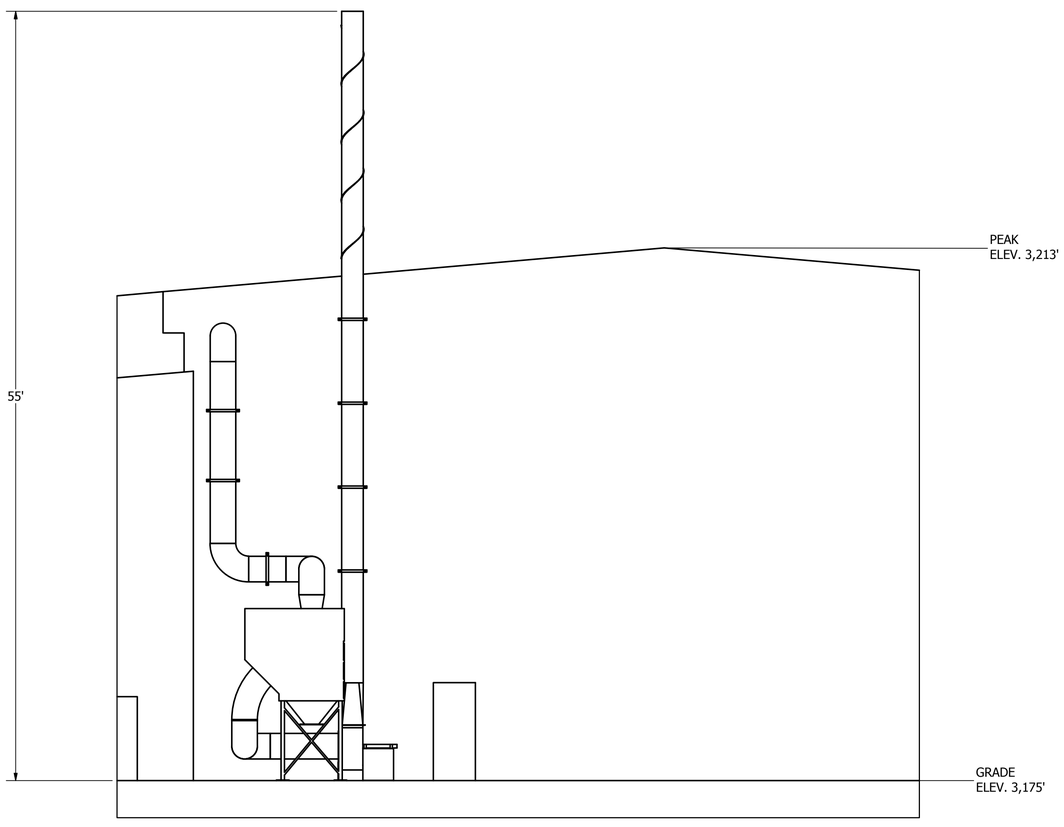
Dynamis Energy LLC,
776 E. Riverside Dr. Ste. 150
Eagle, ID 83616

TITLE
ASH ROOM, BAGHOUSE, STACK, ADA COUNTY

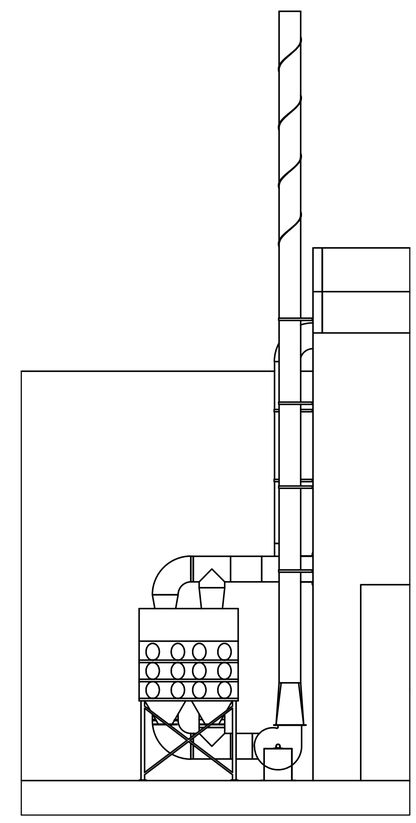
SIZE	DWG NO	REV
D	1003202	-

SCALE: NTS

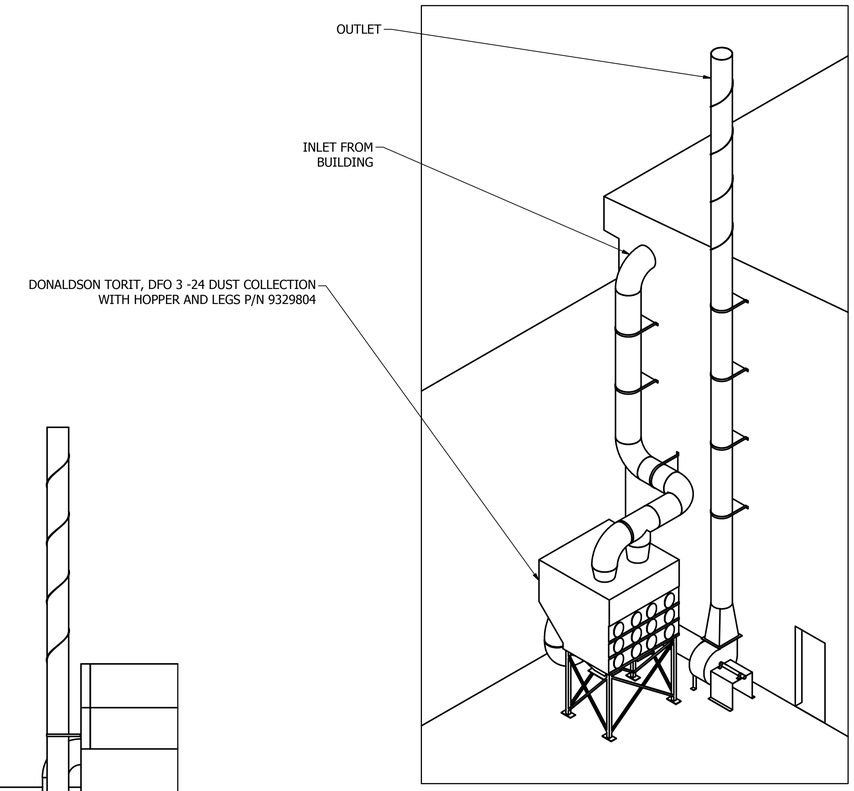
SHEET 1 OF 2



ELEVATION VIEW (EAST SIDE)



ELEVATION VIEW (NORTH SIDE)



DRAWN KS	7/3/2012	DYNAMIS ENERGY	Dynamis Energy LLC, 776 E. Riverside Dr. Ste, 150 Eagle, ID 83616
CHECKED		SIZE D	DWG NO 1003202 — REV -
		SCALE: NTS	SHEET 2 OF 2

24 BISW

Wheel Diameter = 24½ in.
Outlet Area = 3.45 ft.^{2}
Tip Speed = 6.41 x RPM
Maximum BHP = (RPM/750)^3

Minimum Starting HP = ½
Maximum RPM Class I = 1570
Maximum RPM Class II = 2048
Maximum RPM Class III = 2580
Maximum RPM Class IV = 3110

Maximum Open Motor Frame Size

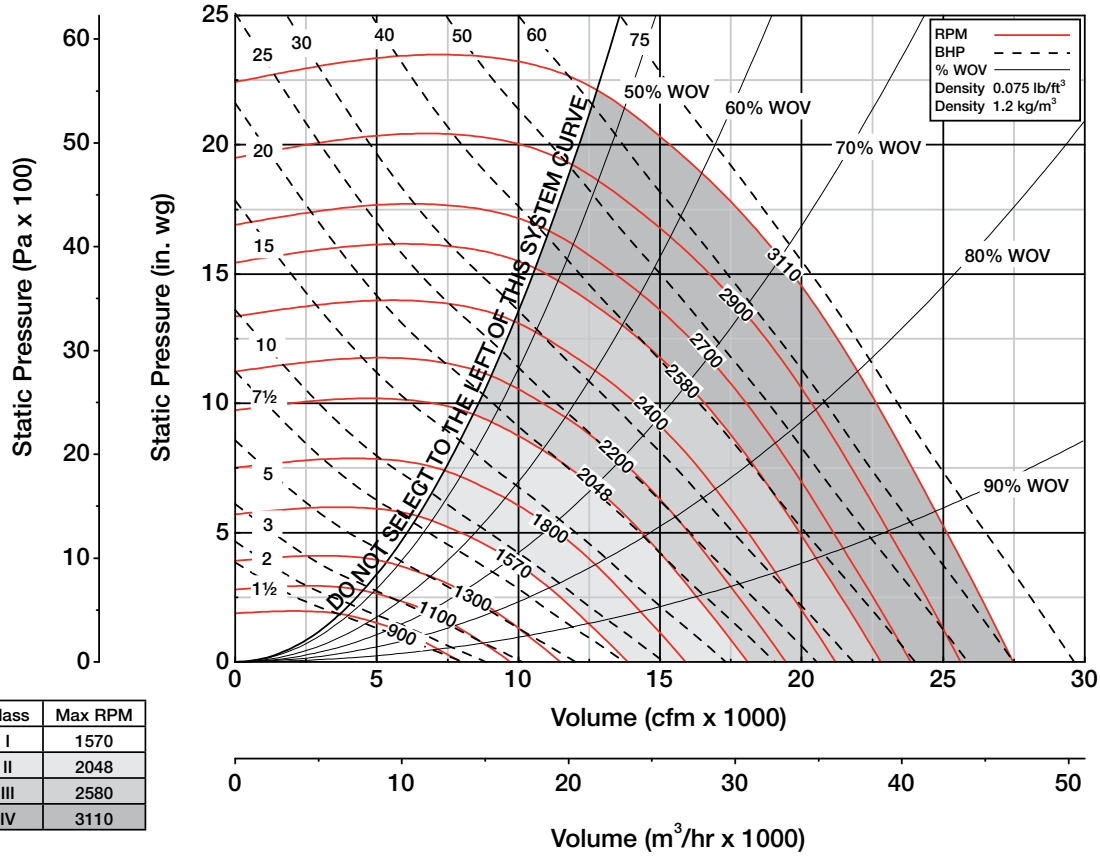
Class	I	II	III	IV
Arr. 9	284T	284T	286T	NA
Arr. 10	215T	284T	NA	NA

CFM	OV	STATIC PRESSURE (in. wg)																			
		0.50		1.00		1.50		2.00		2.50		3.00		3.50		4.00		4.50		5.00	
		RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP
2800	811	513	0.31	665	0.62																
3230	936	541	0.37	686	0.71																
3660	1060	574	0.45	707	0.81	826	1.20														
4090	1185	608	0.53	734	0.92	846	1.35	947	1.80												
4520	1310	646	0.63	762	1.04	868	1.50	967	1.98	1056	2.48										
4950	1434	685	0.75	794	1.18	895	1.66	988	2.18	1076	2.71	1157	3.27								
5380	1559	726	0.89	828	1.34	923	1.85	1012	2.38	1097	2.95	1177	3.54	1251	4.14						
5810	1684	767	1.04	862	1.52	953	2.05	1040	2.61	1120	3.21	1198	3.83	1271	4.46	1340	5.11	1405	5.77		
6240	1808	810	1.21	900	1.72	986	2.27	1068	2.86	1146	3.47	1220	4.12	1292	4.79	1361	5.47	1425	6.17	1487	6.87
6670	1933	853	1.40	939	1.94	1020	2.51	1097	3.13	1174	3.77	1244	4.44	1314	5.14	1381	5.86	1446	6.58	1507	7.32
7100	2057	896	1.61	978	2.18	1055	2.78	1130	3.42	1202	4.09	1272	4.78	1338	5.50	1403	6.25	1466	7.01	1527	7.78
7530	2182	940	1.84	1019	2.45	1093	3.07	1164	3.73	1232	4.43	1301	5.15	1365	5.89	1427	6.66	1488	7.46	1548	8.27
7960	2307	985	2.10	1060	2.75	1131	3.40	1198	4.07	1266	4.80	1329	5.54	1393	6.31	1453	7.10	1512	7.92	1570	8.76
8390	2431	1030	2.38	1102	3.07	1169	3.75	1235	4.45	1299	5.19	1361	5.96	1422	6.76	1482	7.58	1538	8.41	1594	9.28
8820	2556	1075	2.69	1145	3.41	1210	4.13	1273	4.85	1333	5.61	1394	6.41	1451	7.23	1510	8.08	1566	8.94	1620	9.82
9250	2681	1120	3.02	1188	3.78	1250	4.54	1311	5.29	1369	6.07	1428	6.89	1484	7.74	1539	8.61	1595	9.50	1648	10.4

CFM	OV	STATIC PRESSURE (in. wg)																			
		5.00		5.50		6.00		6.50		7.00		7.50		8.00		8.50		9.00		10.00	
		RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP
6200	1797	1485	6.83																		
6690	1939	1508	7.34	1566	8.09	1622	8.86														
7180	2081	1531	7.87	1589	8.66	1645	9.46	1698	10.3												
7670	2223	1554	8.43	1612	9.25	1668	10.1	1721	10.9	1772	11.8	1822	12.7								
8160	2365	1581	9.0	1636	9.87	1691	10.7	1744	11.6	1795	12.5	1845	13.4	1893	14.4	1940	15.3	1985	16.2		
8650	2507	1610	9.6	1664	10.5	1716	11.4	1768	12.4	1819	13.3	1868	14.2	1916	15.2	1962	16.1	2008	17.1	2087	19.0
9140	2649	1641	10.3	1692	11.2	1744	12.1	1794	13.1	1842	14.1	1891	15.0	1939	16.0	1985	17.0	2031	18.0	2109	20.0
9630	2791	1673	10.9	1724	11.9	1772	12.9	1821	13.9	1870	14.9	1916	15.9	1963	16.9	2009	18.0	2054	19.0	2132	21.0
10120	2933	1706	11.7	1756	12.7	1804	13.7	1851	14.7	1897	15.7	1944	16.8	1989	17.8	2033	18.9	2077	20.0	2155	22.0
10610	3075	1740	12.5	1789	13.5	1837	14.5	1883	15.5	1928	16.6	1973	17.7	2017	18.8	2060	19.9	2103	21.0	2178	23.1
11100	3217	1778	13.3	1823	14.3	1870	15.4	1916	16.5	1960	17.5	2003	18.6	2046	19.7	2088	20.9	2130	22.1	2203	24.3
11590	3359	1816	14.2	1860	15.2	1903	16.3	1948	17.4	1993	18.5	2036	19.7	2077	20.8	2118	22.0	2159	23.1	2230	25.4
12080	3501	1854	15.1	1898	16.2	1941	17.3	1982	18.4	2025	19.6	2068	20.8	2110	21.9	2150	23.1	2189	24.3	2257	26.6
12570	3643	1893	16.1	1937	17.2	1979	18.4	2020	19.5	2060	20.7	2101	21.9	2142	23.1	2182	24.3	2221	25.5	2286	27.8
13060	3785	1935	17.1	1976	18.3	2018	19.4	2058	20.6	2098	21.8	2136	23.1	2175	24.3	2215	25.6	2254	26.8	2318	29.1
13550	3927	1977	18.2	2016	19.4	2057	20.6	2097	21.8	2136	23.1	2174	24.3	2211	25.6	2248	26.8	2287	28.1	2350	30.5

CFM	OV	STATIC PRESSURE (in. wg)																			
		10.00		11.00		12.00		13.00		14.00		15.00		16.00		17.00		18.00		20.00	
		RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP
11000	3188	2197	24.0	2277	26.4	2354	28.7	2428	31.1	2500	33.5	2568	36.0	2635	38.4						
11530	3342	2227	25.3	2303	27.7	2379	30.1	2453	32.6	2524	35.1	2593	37.6	2659	40.1	2724	42.7	2786	45.3		
12060	3495	2256	26.5	2332	29.0	2405	31.6	2478	34.1	2549	36.7	2617	39.3	2684	41.9	2748	44.5	2810	47.2		
12590	3649	2287	27.9	2362	30.4	2434	33.0	2504	35.7	2574	38.3	2642	41.0	2708	43.7	2772	46.4	2834	49.1	2954	54.7
13120	3802	2322	29.3	2392	31.9	2464	34.5	2533	37.3	2600	40.0	2667	42.8	2733	45.5	2797	48.3	2859	51.1	2978	56.8
13650	3956	2357	30.8	2427	33.5	2493	36.1	2563	38.9	2629	41.7	2694	44.6	2756	47.4	2821	50.3	2883	53.2	3002	59.0
14180	4110	2392	32.4	2462	35.1	2529	37.8	2593	40.6	2659	43.5	2723	46.4	2785	49.3	2846	52.3	2908	55.3	3027	61.3
14710	4263	2427	34.0	2496	36.8	2563	39.6	2627	42.4	2689	45.3	2753	48.3	2815	51.3	2875	54.4	2933	57.4	3051	63.6
15240	4417	2466	35.7	2532	38.6	2598	41.4	2662	44.4	2722	47.3	2782	50.3	2844	53.4	2904	56.5	2962	59.6	3074	66.0
15770	4571	2506	37.5	2568	40.4	2633	43.4	2696	46.3	2757	49.3	2816	52.4	2873	55.4	2933	58.6	2992	61.9		
16300	4724	2547	39.4	2608	42.3	2668	45.3	2731	48.4	2792	51.5	2851	54.6	2907	57.7	2963	60.9	3021	64.2		
16830	4878	2588	41.3	2649	44.4	2708	47.4	2766	50.5	2827	53.7	2886	56.8	2942	60.0	2997	63.3	3051	66.5		
17360	5031	2630	43.4	2690	46.5	2748	49.6	2805	52.7	2862	55.9	2920	59.2	2977	62.4	3032	65.7				
17890	5185	2671	45.5	2731	48.6	2789	51.8	2845	55.0	2899	58.3	2955	61.6	3012	64.9	3067	68.3				
18420	5339	2715	47.7	2773	50.9	2830	54.1	2886	57.4	2939	60.8	2992	64.1	3047	67.5						
18950	5492	2761	50.1	2814	53.2	2872	56.6	2927	59.9	2980	63.3	3032	66.7	3082	70.2						

Performance certified is for model BISW Arrangement 1, Installation Type B: free inlet, ducted outlet.
Performance ratings do not include the effects of appurtenances (accessories).
Power rating (Bhp) does not include transmission losses.



Class	Max RPM
I	1570
II	2048
III	2580
IV	3110

% WOV = (CFM X 100) / (RPM X 8.84)

Sound Power [dB Ref 10^{-12} watts]

		Inlet Sound Power, L_{Wi}								
RPM	%WOV	1	2	3	4	5	6	7	8	L_{Wi}A
450	100	81	76	71	64	58	51	44	38	67
	80	74	68	64	57	51	45	38	32	60
	60	73	65	60	54	51	44	36	31	57
	50	71	64	59	54	53	45	38	32	58
	40	71	63	58	54	53	45	38	32	57
900	100	88	89	86	81	78	74	64	58	84
	80	84	86	83	78	74	69	62	57	80
	60	83	87	82	76	74	68	64	60	80
	50	84	84	80	75	73	68	65	61	78
	40	85	83	79	75	73	68	66	62	78
1300	100	91	91	98	90	85	86	77	70	94
	80	88	88	96	87	81	80	74	68	91
	60	88	86	93	84	80	78	74	71	88
	50	88	85	91	82	79	76	75	72	87
	40	88	85	93	82	80	77	75	72	88
1800	100	98	95	104	97	94	96	92	82	102
	80	94	91	102	93	89	89	85	78	97
	60	94	87	97	89	87	86	84	80	94
	50	95	88	98	87	86	85	84	82	94
	40	98	93	100	89	86	86	85	82	95
2580	100	105	106	109	110	103	103	102	95	111
	80	101	102	106	106	99	97	95	90	107
	60	101	100	101	102	96	94	93	90	103
	50	102	101	102	102	94	93	93	91	103
	40	105	105	106	104	96	94	93	91	104
3110	100	108	111	113	113	109	107	106	101	115
	80	104	107	109	110	105	102	99	95	111
	60	104	105	105	105	101	99	97	95	107
	50	105	106	107	105	100	98	97	95	107
	40	108	110	110	107	102	98	97	96	109

		Outlet Sound Power, L_{Wo}								
RPM	%WOV	1	2	3	4	5	6	7	8	L_{Wo}A
450	100	84	78	71	67	62	54	47	40	69
	80	84	77	69	62	58	50	43	37	67
	60	83	74	66	59	57	49	44	38	64
	50	81	73	64	58	56	48	45	39	63
	40	80	72	64	58	56	48	45	39	63
900	100	95	94	86	82	82	77	68	61	86
	80	94	91	82	78	77	71	64	59	82
	60	90	89	80	75	74	67	63	60	79
	50	91	88	79	74	73	67	64	64	79
	40	91	88	78	74	72	67	64	64	78
1300	100	102	99	98	92	90	89	82	73	96
	80	99	97	98	89	87	84	77	71	94
	60	96	94	97	86	84	79	74	71	91
	50	95	94	96	85	82	77	73	72	90
	40	95	94	95	84	81	77	74	72	89
1800	100	108	105	107	100	99	99	95	86	105
	80	103	102	104	97	96	94	90	82	101
	60	101	99	101	94	93	89	85	81	99
	50	101	99	99	93	91	87	84	81	97
	40	101	99	98	92	90	86	84	82	96
2580	100	114	114	114	112	107	107	105	99	114
	80	109	110	110	109	104	103	100	94	111
	60	107	108	108	106	102	99	95	91	108
	50	108	108	106	104	100	97	94	91	106
	40	108	108	106	103	99	96	93	91	105
3110	100	118	118	118	115	112	111	109	104	118
	80	113	114	114	112	109	107	105	100	115
	60	111	112	112	109	107	104	100	96	112
	50	111	112	111	107	105	102	99	96	110
	40	111	112	111	107	104	101	98	95	110

The sound power level ratings shown are in decibels, referred to 10^{-12} watts calculated per AMCA Standard 301. Values shown are for inlet L_{Wi}, L_{Wi}A and outlet L_{Wo}, L_{Wo}A sound power levels for Installation Type B: free inlet, ducted outlet. Outlet ratings include the effects of duct end correction. The A-weighted sound ratings shown have been calculated per AMCA International Standard 301.

27 BISW

Wheel Diameter = 27 in.
Outlet Area = 4.19 ft.^{2}
Tip Speed = 7.09 x RPM
Maximum BHP = (RPM/638)^3

Minimum Starting HP = ¾
Maximum RPM Class I = 1425
Maximum RPM Class II = 1859
Maximum RPM Class III = 2342
Maximum RPM Class IV = 2823

Maximum Open Motor Frame Size

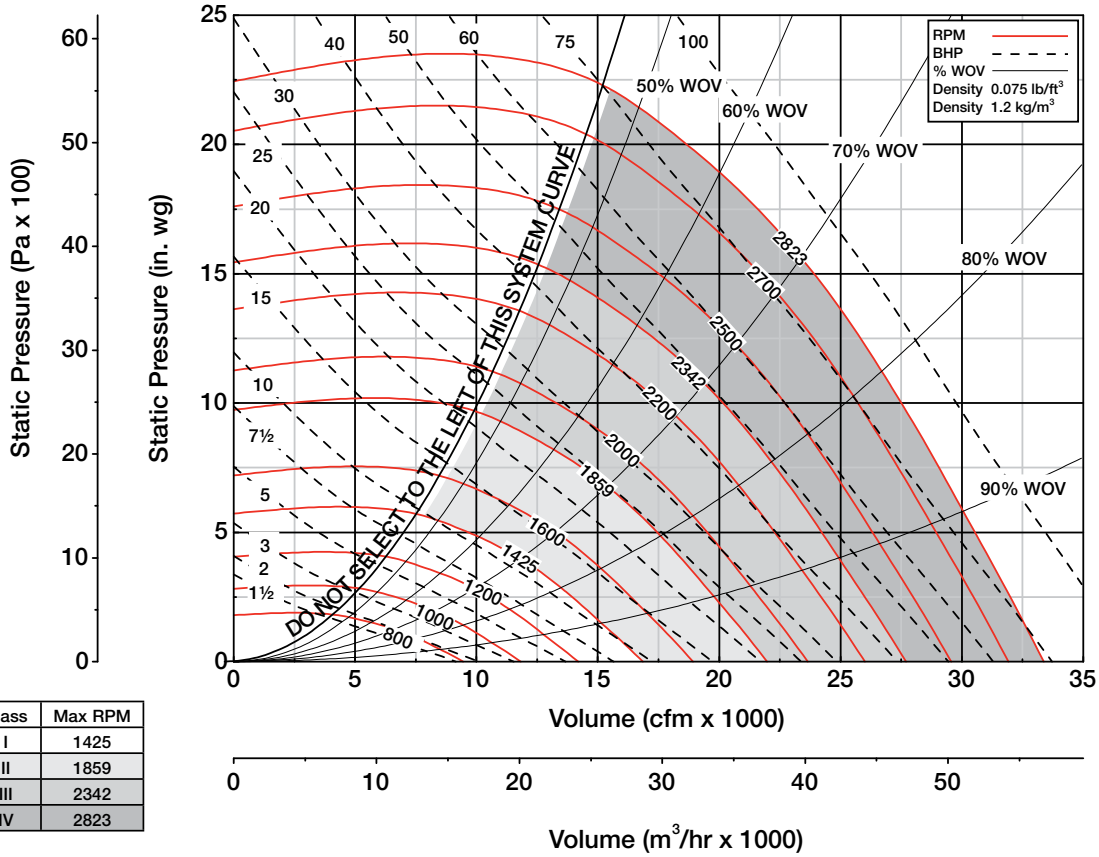
Class	I	II	III	IV
Arr. 9	284T	284T	286T	NA
Arr. 10	254T	284T	NA	NA

CFM	OV	STATIC PRESSURE (in. wg)																			
		0.50		1.00		1.50		2.00		2.50		3.00		3.50		4.00		4.50		5.00	
		RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP
3400	811	465	0.38	604	0.75																
3930	937	492	0.46	622	0.86																
4460	1064	522	0.55	642	0.98	750	1.47														
4990	1190	553	0.65	667	1.12	769	1.64	860	2.19												
5520	1317	588	0.78	693	1.28	789	1.83	879	2.42	960	3.03										
6050	1443	624	0.92	723	1.45	814	2.03	898	2.66	978	3.32	1051	3.99								
6580	1570	662	1.09	754	1.65	840	2.26	920	2.92	996	3.62	1070	4.33	1137	5.06						
7110	1696	700	1.28	786	1.87	868	2.51	946	3.20	1019	3.93	1089	4.68	1156	5.46	1218	6.25	1277	7.05		
7640	1823	739	1.49	821	2.12	898	2.79	972	3.51	1043	4.26	1110	5.05	1175	5.87	1237	6.70	1296	7.55	1351	8.41
8170	1949	779	1.73	856	2.39	930	3.09	1000	3.84	1069	4.63	1133	5.44	1195	6.30	1256	7.18	1314	8.06	1370	8.96
8700	2076	819	1.99	893	2.70	962	3.42	1030	4.21	1095	5.03	1158	5.87	1218	6.75	1276	7.67	1333	8.60	1388	9.54
9230	2202	860	2.28	931	3.04	997	3.79	1061	4.60	1123	5.45	1185	6.33	1243	7.24	1299	8.18	1354	9.15	1407	10.1
9760	2329	901	2.61	968	3.41	1032	4.20	1093	5.02	1154	5.91	1211	6.82	1269	7.76	1323	8.72	1376	9.72	1428	10.8
10290	2455	942	2.96	1007	3.80	1068	4.64	1127	5.49	1185	6.40	1241	7.35	1295	8.32	1350	9.32	1401	10.3	1451	11.4
10820	2582	984	3.34	1047	4.23	1105	5.11	1162	6.00	1216	6.92	1271	7.91	1323	8.91	1376	9.95	1427	11.0	1475	12.1
11350	2708	1026	3.77	1087	4.70	1143	5.63	1197	6.55	1250	7.50	1303	8.50	1354	9.54	1403	10.6	1453	11.7	1501	12.8

CFM	OV	STATIC PRESSURE (in. wg)																			
		5.00		5.50		6.00		6.50		7.00		7.50		8.00		8.50		9.00		10.00	
		RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP
7500	1789	1346	8.27																		
8090	1930	1367	8.88	1420	9.79	1470	10.7														
8680	2071	1388	9.52	1441	10.5	1491	11.4	1540	12.4												
9270	2212	1408	10.2	1461	11.2	1512	12.2	1560	13.2	1607	14.3	1652	15.3								
9860	2353	1433	10.9	1482	11.9	1533	13.0	1581	14.1	1628	15.1	1672	16.2	1716	17.3	1758	18.5				
10450	2494	1458	11.6	1507	12.7	1555	13.8	1602	14.9	1648	16.0	1693	17.2	1737	18.3	1779	19.5	1820	20.7	1892	22.9
11040	2634	1486	12.4	1533	13.5	1580	14.6	1625	15.8	1669	17.0	1714	18.2	1758	19.4	1800	20.6	1840	21.8	1913	24.1
11630	2775	1515	13.2	1561	14.3	1606	15.5	1650	16.7	1694	17.9	1736	19.2	1779	20.4	1821	21.7	1861	22.9	1933	25.4
12220	2916	1544	14.1	1590	15.3	1634	16.5	1676	17.7	1719	18.9	1761	20.2	1802	21.5	1842	22.8	1882	24.1	1954	26.6
12810	3057	1574	15.0	1620	16.2	1663	17.5	1705	18.7	1746	20.0	1786	21.3	1827	22.7	1866	24.0	1905	25.4	1974	27.9
13400	3198	1608	16.0	1649	17.3	1693	18.5	1734	19.8	1775	21.1	1814	22.5	1853	23.8	1891	25.2	1930	26.6	1996	29.3
13990	3338	1643	17.1	1683	18.3	1722	19.7	1764	21.0	1804	22.3	1843	23.7	1881	25.1	1918	26.5	1955	27.9	2020	30.7
14580	3479	1677	18.2	1717	19.5	1756	20.8	1794	22.2	1833	23.6	1872	25.0	1910	26.4	1947	27.9	1982	29.3	2045	32.1
15170	3620	1712	19.3	1752	20.7	1790	22.1	1828	23.5	1864	24.9	1902	26.3	1939	27.8	1976	29.3	2011	30.8	2070	33.5
15760	3761	1749	20.6	1787	22.0	1825	23.4	1862	24.8	1898	26.3	1932	27.8	1969	29.3	2005	30.8	2040	32.3	2099	35.1
16350	3902	1787	21.9	1823	23.3	1860	24.8	1896	26.2	1932	27.7	1966	29.2	2000	30.8	2035	32.3	2070	33.9	2128	36.8

CFM	OV	STATIC PRESSURE (in. wg)																			
		10.00		11.00		12.00		13.00		14.00		15.00		16.00		17.00		18.00		20.00	
		RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP	RPM	BHP
13400	3198	1996	29.3	2068	32.1	2138	35.0	2206	37.9	2270	40.8	2333	43.8	2393	46.8						
14040	3350	2022	30.8	2092	33.7	2161	36.7	2228	39.7	2292	42.7	2355	45.8	2415	48.9	2473	52.0	2530	55.2		
14680	3503	2049	32.3	2118	35.4	2184	38.4	2250	41.5	2315	44.7	2377	47.8	2437	51.0	2495	54.2	2552	57.5		
15320	3656	2077	33.9	2145	37.0	2211	40.2	2274	43.4	2337	46.7	2399	49.9	2459	53.2	2517	56.5	2574	59.8	2682	66.6
15960	3809	2109	35.7	2172	38.8	2237	42.1	2300	45.4	2361	48.7	2422	52.0	2481	55.4	2539	58.8	2596	62.2	2704	69.2
16600	3961	2140	37.5	2204	40.7	2264	44.0	2327	47.3	2388	50.8	2446	54.2	2503	57.7	2562	61.2	2618	64.7	2726	71.8
17240	4114	2172	39.4	2235	42.7	2296	46.0	2354	49.4	2414	52.9	2472	56.5	2529	60.0	2584	63.7	2640	67.3	2748	74.5
17880	4267	2204	41.4	2267	44.8	2327	48.2	2385	51.6	2441	55.1	2499	58.8	2555	62.4	2610	66.1	2663	69.9	2770	77.3
18520	4420	2239	43.4	2298	46.9	2358	50.4	2416	53.9	2471	57.5	2526	61.1	2582	64.9	2636	68.7	2689	72.5	2791	80.2
19160	4572	2275	45.6	2331	49.1	2390	52.7	2448	56.3	2503	60.0	2556	63.7	2608	67.4	2663	71.3	2716	75.2		
19800	4725	2312	47.9	2368	51.5	2422	55.1	2479	58.8	2534	62.5	2588	66.3	2639	70.1	2689	74.0	2742	78.0		
20440	4878	2349	50.2	2405	53.9	2458	57.6	2511	61.4	2566	65.2	2619	69.1	2671	73.0	2720	76.9	2769	80.8		
21080	5031	2387	52.7	2441	56.4	2494	60.2	2545	64.0	2598	67.9	2651	71.9	2702	75.9	2752	79.9				
21720	5183	2424	55.2	2479	59.0	2531	62.9	2582	66.8	2631	70.8	2682	74.8	2733	78.9	2783	83.0				
22360	5336	2464	57.9	2516	61.8	2568	65.7	2619	69.7	2667	73.8	2715	77.8	2765	82.0						
23000	5489	2505	60.8	2554	64.6	2606	68.7	2656	72.7	2704	76.8	2751	81.0	2797	85.2						

Performance certified is for model BISW Arrangement 1, Installation Type B: free inlet, ducted outlet.
Performance ratings do not include the effects of appurtenances (accessories).
Power rating (Bhp) does not include transmission losses.



Class	Max RPM
I	1425
II	1859
III	2342
IV	2823

% WOV = (CFM X 100) / (RPM X 11.8)

Sound Power [dB Ref 10^{-12} watts]

Inlet Sound Power, L_{Wi}

RPM	%WOV	1	2	3	4	5	6	7	8	L_{Wi}A
400	100	83	75	71	63	58	51	43	37	67
	80	76	67	63	56	51	44	37	32	60
	60	75	63	59	53	51	43	36	30	57
	50	73	63	58	54	53	44	37	32	57
	40	72	61	58	54	53	44	38	31	57
800	100	89	89	86	81	78	73	63	58	83
	80	86	87	82	78	74	68	61	56	80
	60	85	88	81	76	73	68	64	60	80
	50	84	84	79	75	73	68	65	61	78
	40	86	84	78	75	73	68	66	62	78
1200	100	93	94	99	91	86	86	78	71	94
	80	90	90	97	87	82	81	74	69	91
	60	89	88	93	84	80	78	75	71	88
	50	90	87	92	83	80	77	76	73	87
	40	89	88	93	83	81	78	76	73	88
1700	100	100	98	106	99	96	97	92	83	103
	80	96	94	104	94	91	90	86	79	99
	60	95	90	99	90	88	87	85	82	96
	50	96	91	100	89	87	87	86	83	96
	40	99	96	102	91	88	87	86	84	97
2342	100	107	106	111	109	104	104	102	94	111
	80	103	102	108	106	99	98	95	89	107
	60	103	100	103	101	96	95	93	90	103
	50	104	101	104	101	95	94	93	91	103
	40	107	105	107	103	96	95	94	92	105
2823	100	110	112	114	115	109	108	107	100	116
	80	106	108	111	112	105	102	100	95	112
	60	107	106	107	108	101	99	98	95	109
	50	107	107	108	108	100	98	98	96	108
	40	110	111	111	110	102	99	98	96	111

Outlet Sound Power, L_{Wo}

RPM	%WOV	1	2	3	4	5	6	7	8	L_{Wo}A
400	100	85	77	70	66	62	53	46	40	69
	80	85	76	68	61	58	49	42	36	66
	60	84	73	65	58	57	47	44	38	64
	50	82	71	63	58	57	47	44	39	63
	40	81	71	63	58	57	47	45	39	63
800	100	95	94	85	82	81	76	67	60	86
	80	94	91	82	78	77	71	64	58	82
	60	91	89	79	75	73	67	63	60	79
	50	91	87	78	74	72	67	64	64	78
	40	91	88	77	74	72	67	64	64	78
1200	100	103	100	98	92	91	89	82	73	97
	80	100	98	98	90	88	84	77	71	94
	60	97	96	97	87	84	79	75	72	92
	50	96	95	96	85	82	78	74	73	90
	40	97	95	95	84	82	78	75	73	90
1700	100	109	107	109	101	100	100	96	87	107
	80	104	104	105	98	97	95	91	83	103
	60	102	101	103	96	95	91	86	83	100
	50	103	100	101	94	92	89	86	83	98
	40	103	100	100	93	91	88	86	83	97
2342	100	116	114	115	111	108	107	105	98	115
	80	111	111	111	108	105	103	100	94	111
	60	109	108	109	106	102	99	95	91	108
	50	109	108	107	104	100	97	94	91	106
	40	109	108	107	103	99	96	94	91	106
2823	100	119	119	119	118	113	112	110	104	120
	80	114	115	115	115	110	108	105	100	116
	60	112	112	113	112	107	104	100	96	114
	50	113	113	112	111	105	102	99	96	112
	40	112	113	111	110	104	101	98	96	111

The sound power level ratings shown are in decibels, referred to 10^{-12} watts calculated per AMCA Standard 301. Values shown are for inlet L_{Wi}, L_{Wi}A and outlet L_{Wo}, L_{Wo}A sound power levels for Installation Type B: free inlet, ducted outlet. Outlet ratings include the effects of duct end correction. The A-weighted sound ratings shown have been calculated per AMCA International Standard 301.

From: Shannon Manoulian <smanoulian@jbrenv.com>
Sent: Thursday, July 26, 2012 12:16 PM
To: Darrin Pampaian
Subject: Dynamis SNCR System
Attachments: DNT SNCR PROPOSAL July 2012_no price.pdf; Facility PTE.pdf

Hi Darrin,

Please find attached the control guarantee (40% control for incoming NOx up to 50 lb/hr) for the Dynamis SNCR and the revised EI.

The ammonia slip will be captured by the scrubber system. Ammonia will not be injected directly; the system will use urea, which will react to form ammonia in the flue gas. The urea injection flow rate is approximately 50% of 5 gallon/hr (or 2.5 gal/hr). This is based on the MCR reagent flow rate multiplied by the urea concentration. The SNCR has a feedback control from the CEMS to monitor and adjust the flows. So the monitoring schedule is continuous (or as frequent as the CEMS samples).

The attachment will also be included with the revised modeling report.

Please let me know if the information above is sufficient for you review, or if you require any additional information.

Best Regards,
Shannon

Shannon Manoulian, P.E.
JBR Environmental Consultants, Inc.
7669 West Riverside Drive, Suite 101
Boise, ID 83714
208-853-0883 (phone)
208-853-0884 (fax)
734-624-4555 (cell)
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1.0 INTRODUCTION

De-NOx Technologies, LLC (DNT) is pleased to offer Dynamis Energy, LLC the following revised Firm Price Proposal for the design and supply of a urea-based SNCR system. This system is to be installed on one 200,000pph MSW Gasification unit in Boise ID. The proposed system will utilize 50wt% urea solution.

DNT will provide the process design, mechanical design, electrical and control design, equipment selection, equipment fabrication, injector supply, and process guarantees.

The major design parameters are presented in Table 1.

TABLE 1
Design Conditions

Design Parameters	Typical
Combustor Steam Rate (pph)	200,000
Oxygen Level (% v)	4-6
Carbon Monoxide (lb/MMBTU)	<0.2
Load Range (%)	70-100
Furnace Exit Gas Temperature (degF)	1900-2000
Estimated MCR Reagent Consumption, GPH	5
Minimum Gas Residence Time after injection and before Boiler, sec	0.75
Design Uncontrolled NOX_x (pph, as NO2)	50
Guaranteed Controlled NOX_x (pph)	30

2.0 SCOPE OF SUPPLY

DNT will provide the following design services and equipment:

2.1 Equipment

- One (1) 6000 gallon non-metallic atmospheric pressure Storage Tank. The tank can be located outdoors on a properly designed level concrete foundation. It will be supplied with heating pads and temperature controls to maintain 80 degF at the local winter design temperature.

  The storage tank will be supplied with:

  - Side Bolted Manway
  - Corrosion barrier
  - UV resistant outer treatment
  - Hold Down and Lifting Lugs
  - Flanged fittings for Pump Suction, Vent, Fill, and Recirc
  - Isolation Valves
  - Level Indicator/Transmitter
  - Temperature Indicator/Transmitter

- One Control Module will be supplied to be located in a climate controlled enclosure (enclosure by others) in immediate proximity to the Storage Tank. This module will: 1)provide circulation and external heating of concentrated reagent, 2)filter and regulate the flow of reagent and dilution water, and 3)mix the reagent with dilution water for the boiler. The module will be pre-assembled.

  The proper amount of reagent is determined based upon feedback from a CEM system, and algorithms resident in the PLC System. Urea will be metered to the boiler unit through positive displacement pumps. Materials of construction for the concentrated reagent and diluted reagent lines shall be SS piping and/or tubing. Duplex strainers of 316 SS construction, capable of continuous filtering of the reagent and dilution water shall be provided. The device shall be capable of being maintained while on line.

  The Control Module will be supplied with a NEMA 4X enclosure which houses the Main Circuit Breaker/Handle, AB PLC components,,

motor starters, instrument/ power terminal strips, 24VDC Power Supply, and variable speed drives. The system will be capable of full manual operation from the face of the panel.

The Module will be supplied with reagent flow measurement, reagent circulation, external electric circulation heater, and automatic flush-out.

- Distribution Module. One Distribution Module will be provided in near proximity to the injection nozzles. The module distributes the supply of diluted reagent to each injector, as well as control atomizing air pressure. These modules are designed to save floor space and can be mounted on walls, columns, or over handrail.

- Dual Fluid Nozzle Atomizing Injectors. These injectors are DNT's proven and proprietary design. They have proven, excellent, service life on refuse and biomass units.

  The exact location of these ports will be determined during the contract phase of the project. This proposal assumes 6 injectors generally located 0.5 sec prior to the first convective tube surface. The injectors are inserted and retracted by hand. Flexible hoses, attached to the injectors with quick connects, will be supplied.

2.2 Engineering and Start-up Services. These services would include:

- P&ID's, Equipment Arrangement Drawings, equipment fabrication drawings, logic and interconnect drawings

- Specify, select, purchase, prefabricate, and deliver the equipment specified above.

- Five Maintenance and Operation Manuals.

2.3 Provided by Owner

- Approximately 3 GPM of dilution water @ 80 psig to the Control Module. This dilution water should be softened and generally be of drinking quality.

- Compressed Air – Approximately 90 scfm at a minimum pressure of 80 psig to the Distribution Panel.

- Fused disconnects for power to the tank panel, heat tracing and Control Module, as follows:
  - Control Module – 480 VAC, 20 Amp.
  - Tank – 120VAC, 4000 watt

- All local permits and/or licenses.

- Compliance and/or Performance Testing.

- Terminations to the Central Control Station, any additions to hardware/software and graphics/configuration.

- All Receiving and Installation, including all piping heat tracing.

3.0 PRICING

The firm price for the Scope as described herein is [redacted] freight excluded. The price includes 5 days of on-site Field Services for Mechanical Check-Out, Training and Start-Up. DNT's Terms and Conditions attached.

4.0 PROJECT SCHEDULE

Begin Equipment Design	At Notice to Proceed
Submit Mech and Elec Drawings for Approval	4 weeks after NTP
Shipment of Equipment	12 weeks after Approvals

Dynamis Energy, LLC
Ada County WTE Facility

FACILITY POTENTIAL TO EMIT - CRITERIA POLLUTANTS

	Criteria Pollutants											
	NOx Emissions		CO Emissions		PM-10/PM-2.5 Emissions		SOx Emissions		VOC Emissions		Lead Emissions	
Description	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Thermal Conversion Unit - Peak	17.96	52.43	10.90	31.83	3.66	10.68	8.54	24.94			0 03	0.09
Thermal Conversion Unit - OffPeak	2.65	3.86	1 61	0.54	0.54	0.79	1.26	1 84			0.00	0.01
Cooling Tower					0.02	0.08						
Ash System					0.45	1.97					5.10E-04	2.23E-03
Emergency Generator	1.30	0.33	0 26	0.07	0.03	0.01	0.98	0 25	1.19	0.30		
Ignition Systems	0.28	1.23	0 39	1.72	0.02	0.09	0.00	0 00	0.03	0.11	2.33E-06	1.02E-05
Total	**22.183**	**57.843**	**13.164**	**34.149**	**4.720**	**13.616**	**10.786**	**27.030**	**1.211**	**0.409**	**0.0358**	**0.099**

FACILITY POTENTIAL TO EMIT - TAPS

NON-CARCINOGENS (POUNDS PER HOUR)						
Pollutant	CAS #	TAP Emissions - Max (lb/hr)	TAP Emissions - Average (lb/hr)	TAP Emissions (tpy)	Screening Level (lb/hr)	Modeling? (Y/N)
Acrolein	107-02-8	1.13E-04	1.13E-04	2.82E-05	1.70E-02	No
Aluminum	7429-90-5	1.05E-01	1.02E-01	4.48E-01	6 67E-01	No
Antimony	7440-36-0	7.86E-04	5.63E-04	2.46E-03	3 30E-02	No
Barium	7440-39-3	7.92E-04	7.32E-04	3.21E-03	3 30E-02	No
Chromium	7440-47-3	1.85E-03	1.35E-03	5.92E-03	3 30E-02	No
Cobalt	7440-48-4	1.71E-03	1.62E-03	7.09E-03	3 30E-03	No
Copper	7440-50-8	1.12E-03	9.08E-04	3.98E-03	6.70E-02	No
Fluoride (as F) (Hydrogen Fl)	16984-48-8	2.84E-03	2.03E-03	8.91E-03	1 67E-01	No
Hexane	110-54-3	8.40E-03	8.40E-03	3.68E-02	1.20E+01	No
Hydrogen Chloride	7647-01-0	5.95E-01	5.95E-01	2 61E+00	5 00E-02	See Footnote 1
Manganese	7439-96-5	6.96E-03	5.23E-03	2.29E-02	3 33E-01	No
Mercury*	7439-97-6	3.10E-03	2.22E-03	9.72E-03	N/A	*
Molybdenum	7439-98-7	2.24E-03	1.61E-03	7.06E-03	3 33E-01	No
Naphthalene**	91-20-3	3.04E-06	3.04E-06	1 25E-05	9.10E-05	No
Pentane	109-66-0	1.21E-02	1.21E-02	5.31E-02	1.18E+02	No
Phosphorous	7723-14-0	2.66E-03	2.66E-03	1.17E-02	7 00E-03	No
Selenium	7782-49-2	2.22E-03	1.59E-03	6.95E-03	1 30E-02	No
Silver	7440-22-4	2.92E-07	2.92E-07	1.28E-06	7 00E-03	No
Toluene	108-88-3	5.15E-04	5.15E-04	1 94E-04	2.50E+01	No
o-Xylene	1330-20-7	3.48E-04	3.48E-04	8.70E-05	2.90E+01	No
Zinc	7440-66-6	3.42E-01	3.09E-01	1 35E+00	6 67E-01	No

*Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215.

**Although listed as a noncarcinogen in the Rules, DEQ has determined that naphthalene is a possible/probable carcinogen. Compliance for naphthalene emissions should be based on the EL or AACC listed in Section 586 for PAH.
1. Regulated under NSPS Subpart Eb, excluded from modeling under IDAPA 58 01.01 210.20.

CARCINOGENS (POUNDS PER HOUR)						
Pollutant	CAS #	TAP Emissions - Max (lb/hr)	TAP Emissions - Average (lb/hr)	TAP Emissions (tpy)	Screening Level (lb/hr)	Modeling? (Y/N)
Acetaldehyde	75-07-0	9.37E-04	9.37E-04	5.35E-05	3 00E-03	No
Arsenic	7440-38-2	7.46E-07	7.46E-07	3.27E-06	1 50E-06	No
Benzene	71-43-2	1.15E-03	1.15E-03	3 28E-04	8.00E-04	Yes
Beryllium	7440-41-7	4.48E-08	4.48E-08	1.96E-07	2.80E-05	No
Cadmium	7440-43-9	3.48E-03	2.50E-03	1.09E-02	3.70E-06	See Footnote 1
Dioxin/Furan	1746-01-6	4.49E-09	3.21E-09	1.41E-08	1.50E-10	See Footnote 1
Formaldehyde	50-00-0	1.79E-03	1.79E-03	1 89E-03	5.10E-04	Yes
Nickel	7440-02-0	1.51E-02	8.69E-03	3 81E-02	2.70E-05	Yes
Benzo(a)pyrene	50-32-8	5.60E-09	5.60E-09	2.45E-08	2.00E-06	No
Benz(a)anthracene	56-55-3	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Benzo(b)fluoranthene	205-82-3	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Benzo(k)fluoranthene	205-99-2	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Chrysene	218-01-9	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Dibenzo(a,h)anthracene	53-70-3	5.60E-09	5.60E-09	2.45E-08	2.00E-06	No
Indeno(1,2,3-cd)pyrene	193-39-5	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Total PAHs		2.45E-07	2.45E-07	1 07E-06	9.10E-05	No

Dynamis Energy WTE Facility
Thermal Conversion System
Thermal Conversion Unit

Total MSW Throughput	367.2	tpd
Total MSW Throughput	15.30	ton/hr
Total MSW Throughput	30600	lb/hr
Peak Operating Hours	5840	hr/yr
Off-Peak Operating Hours	2920	hr/yr
Peak Exhaust Flow	150,865	acfm @ 125.4F
Off-Peak Exhaust Flow	39,100	acfm @ 134.5F

Hours	7am - 11pm	11pm-7am
Throughput (tpd)	342	25.2
Throughput (tph)	21.375	3.15
Percent of day	0.67	0.33

Pollutant Emission Factors	PM/PM10/ PM2.5 lb/ton	SO2 lb/ton	NOx lb/ton	CO lb/ton	Lead lb/ton
Thermal Conversion Unit Exhaust	0.29	1.39	1.4	0.51	1.44E-03

PM, NOx, CO, SO2, Lead Emission factor from source test averages
*SO2 Emission rate based on scrubber manufacturer guarantee of 71.25% control. PM2.5 emission rate based on scrubber manufacturere guarantee of 41%.
*NOx Emission rate based on SNCR manufacturer guarantee of 40% control.

7am-11pm - PEAK

	PM/PM10/PM2.5		SO_2		NOx		CO		Lead	
Pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Thermal Conversion Unit Exhaust Uncontrolled	6.20	18.10	29.71	86.76	29.93	87.38	10.90	31.83	0.03	0.09
Thermal Conversion Unit Exhaust Controlled	3.66	10.68	8.54	24.94	17.96	52.43	10.90	31.83	0.03	0.09
Controlled Boiler Stack Emissions (Thermal Unit + Ignition System)	3.68	10.74	8.54	24.94	18.23	53.25	11.29	32.98	0.03	0.09

11pm-7am - OFF PEAK

	PM/PM10/PM2.5		SO_2		NOx		CO		Lead	
Pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Thermal Conversion Unit Exhaust Uncontrolled	0.91	1.33	4.38	6.39	4.41	6.44	1.61	0.54	0.00	0.01
Thermal Conversion Unit Exhaust Controlled	0.54	0.79	1.26	1.84	2.65	3.86	1.61	0.54	0.00	0.01
Controlled Boiler Stack Emissions (Thermal Unit + Ignition System)	0.56	0.82	1.26	1.84	2.93	4.27	2.00	1.11	0.005	0.01

TOXIC AIR POLLUTANTS (TAPs) CALCULATIONS

NON CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	TAP Emission Factor (lb/ton)	Peak TAP Emissions (lb/hr)	Off Peak TAP Emissions (lb/hr)	Average TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling (based on peak)? (Y/N)	Modeling (based on Average)? (Y/N)
Aluminium	7429-90-5	4.74E-04	8.11E-03	1.19E-03	5.80E-03	6.67E-01	No	No
Antimony	7440-36-0	4.60E-05	7.86E-04	1.16E-04	5.63E-04	3.30E-02	No	No
Barium	7440-39-3	1.23E-05	2.11E-04	3.10E-05	1.51E-04	3.30E-02	No	No
Chromium	7440-47-3	1.03E-04	1.76E-03	2.60E-04	1.26E-03	3.30E-02	No	No
Copper	7440-50-8	4.33E-05	7.41E-04	1.09E-04	5.30E-04	6.70E-02	No	No
Cobalt	7440-48-4	1.77E-05	3.03E-04	4.47E-05	2.17E-04	3.30E-03	No	No
Hydrogen Chloride	7647-01-0	See Note 1 Below	5.95E-01	5.95E-01	5.95E-01	5.00E-02	Mode ing not required (IDAPA 58.01.01 210.20)	
Hydrogen Flouride	NA	1.33E-04	2.84E-03	4.19E-04	2.03E-03	1.67E-01	No	No
Manganese	7439-96-5	3.56E-04	6.08E-03	8.96E-04	4.35E-03	3.33E-01	No	No
Mercury	7439-97-6	1.45E-04	3.10E-03	4.57E-04	2.22E-03	N/A	See Note 2 Below	
Molybdenum	7439-98-7	1.30E-04	2.22E-03	3.27E-04	1.59E-03	3.33E-01	No	No
Selenium	7782-49-2	1.30E-04	2.22E-03	3.27E-04	1.59E-03	1.30E-02	No	No
Zinc	7440-66-6	6.68E-03	1.14E-01	1.68E-02	8.18E-02	6.67E-01	No	No

TAPs Emission factor from source test averages.
1. HCl emission rate of 0.595 lb/hr based on baghouse manufacturer guarantee

2. Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215
The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (w th the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	TAP Emission Factor (lb/ton)	Peak TAP Emissions (lb/hr)	Off Peak TAP Emissions (lb/hr)	Average TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling (based on peak)? (Y/N)	Modeling (based on Average)? (Y/N)	Stack Emissions (Thermal Unit + Ignition System) PEAK lb/hr	PEAK tpy	OFF PEAK lb/hr	OFF PEAK tpy
Cadmium	7440-43-9	2.02E-04	3.46E-03	5.10E-04	2.48E-03	3.7E-06	Mode ing not required (IDAPA 58.01.01 210.20)					
Dioxin/Furan		2.10E-10	4.49E-09	6.62E-10	3.21E-09	1.50E-10	Mode ing not required (IDAPA 58.01.01 210.20)					
Nickel	7440-02-0	8.81E-04	1.51E-02	2.22E-03	8.63E-03	2.70E-05	Yes	Yes	1.51E-02	4.40E-02	2.23E-03	3.25E-03

TAPs Emission factor from source test averages.
The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (w th the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

Dynamis Energy WTE Facility
Thermal Conversion System - Hidden Hollow Landfill
Thermal Conversion Units - Ignition Systems Criteria Pollutants

Primary gasification ignition systems will operate on natural gas. Primary chamber ignition will be evenly distributed hroughout the day; independent of MSW throughput and peak/off-peak operation.

CRITERIA POLLUTANT COMBUSTION CALCULATIONS
NATURAL GAS

Emission Unit	Fuel Usage		Conversions	
Primary Chamber Ignition (total)	111,953 scf/day		40862845	1020 MMBtu/10^6 scf
Primary Chamber Ignition (total)	4.76 MMBtu/hr			

Emission Factors

NOx	100 lb/10^6 scf	AP-42, Table 1.4-1, 1998
CO	84 lb/10^6 scf	AP-42, Table 1.4-1, 1998
PM-10	7.6 lb/10^6 scf	AP-42, Table 1.4-2, 1998
SOx	0.6 lb/10^6 scf	AP-42, Table 1.4-2, 1998
VOC	5.5 lb/10^6 scf	AP-42, Table 1.4-2, 1998
Lead	0.0005 lb/10^6 scf	AP-42, Table 1.4-2, 1998

Description	Capacity (MMBtu/hr)	Throughput (scf/hr)	Pounds per Hour					
			NOx Emissions (lb/hr)	CO Emissions (lb/hr)	PM-10/PM-2.5 Emissions (lb/hr)	SOx Emissions (lb/hr)	VOC Emissions (lb/hr)	Lead Emissions (lb/hr)
Primary Chamber Ignitions - Uncontrolled	4.76	4,665	0.4665	0.3918	0.0355	0.0028	0.0257	0.0000023
Primary Chamber Ignitions - Controlled	4.76	4,665	0.2799	0.3918	0.0209	0.0008	0.0257	0.0000023

*SO2 Emission rate based on scrubber manufacturer guarantee of 71.25% control. PM2.5 emission rate based on scrubber manufacturere guarantee of 41%.

*NOx Emission rate based on SNCR manufacturer guarantee of 40% control.

Description	Capacity (MMBtu/hr)	Throughput (scf/yr)	Ton per Year					
			Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)
Primary Chamber Ignitions - Uncontrolled	4.76	4,665	2.04	1.72	0.16	0.01	0.11	1.02E-05
Primary Chamber Ignitions - Controlled (Peak)	4.76	4,665	0.82	1.14	0.06	0.00	0.07	0.00
Primary Chamber Ignitions - Controlled (Off-Peak)	4.76	4,665	0.41	0.57	0.03	0.00	0.04	0.00

From: Shannon Manoulian [mailto:smanoulian@jbrenv.com]
Sent: Monday, July 30, 2012 11:16 AM
To: Kevin Schilling; Darrin Mehr
Cc: Darrin Pampaian
Subject: Dynamis WTE Facility Revised Modeling

Hi Kevin and Darrin,

Please find attached the revised modeling report for the Dynamis Ada County WTE facility. The model files are too big to email, even as a zipped file, so I will be bringing them over to DEQ on CD along with a hard copy of the report shortly.

Please let me know if you have any questions or comments.

Best Regards,
Shannon

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Documents for Certification:

- **Attachment: July 30, 2012 Modeling Report Addendum (appendices were not included)**
- **(Hand-Delivered Compact Disc) Revision 4 Electronic Modeling Demonstration Files. The Revision 4 files replace all previous modeling demonstration submittals**

July 30, 2012 Modeling Report Addendum (appendices were not included with this addendum)

July 30, 2012 Submittal

creating solutions for today's environment

July 30, 2012

Mr. Darrin Mehr
Air Quality Analyst
Idaho Department of Environmental Quality
1410 North Hilton
Boise, Idaho 83706-1255

Re: Dynamis Energy, LLC, Boise
Revised Air Dispersion Modeling

On July 3, 2012, JBR and IDEQ met to discuss issues associated with the air dispersion modeling submitted to DEQ in support of the PTC application for the Dynamis Energy, LLC (Dynamis) Ada County WTE Facility. These issues were also outlined in the document titled "Dynamis Energy Modeling Discussion Issues – July 3, 2012", prepared by IDEQ. In a letter to DEQ dated July 9, 2012, JBR outlined the proposed resolution to each issue.

Attached to this letter are the revised Air Dispersion Modeling Report and accompanying model files, as well as additional supporting information. The main issue requiring resolution was that the coordinate system used to establish elevations for receptors was not consistent with the coordinate system used for the site boundary and the base elevation. Property boundary and source location coordinates were provided to JBR by another consulting firm. It was indicated that the coordinates were provided in the NAD83 datum; however, upon further review and import of the modeled domain into Google Earth, it was determined that coordinates were not provided in NAD83 datum. Using Google Earth imagery and scaled site plans (as provided in the permit application and also included in the revised model report), the property boundary, buildings, and sources were shifted to be consistent with the correct NAD83 locations. The ambient air boundary was also expanded to limit model impacts due to the revised site location as well as provide Dynamis with future flexibility on utility easement location and access.

In addition, Dynamis will install a Selective Non-Catalytic Reduction (SNCR) system to reduce NOx emissions from the thermal conversion unit. The SNCR manufacturer has guaranteed NO_x reduction of at least 40%, based on incoming loading of up to 50 lb/hr NO_x.

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Manufacturer guarantee information for the SNCR is included in Appendix B of the model report.

There has also been additional concern from DEQ regarding substantiation of the in-stack NO_2/NO_x ratio used for the thermal conversion unit. The NO_2/NO_x in-stack ratio of 0.15 for the thermal conversion unit was conservatively based on a blend of in-stack ratios for natural gas and diesel generator emissions as found in "Assessment of Non-Regulatory Options in AERMOD, Specifically OLM and PVMRM" from the San Joaquin Valley Air Pollution Control District. Based on syngas properties estimated by Dynamis, as well as source test data used to calculate emissions factors for the unit, the syngas produced by the thermal unit will be much more similar to natural gas than diesel. Therefore by using an average calculated based on the maximum NO_2/NO_x ratio for natural gas internal combustion engines and the recommended ratio for diesel internal combustion engines, the NO_2/NO_x in-stack ratio of 0.15 is reasonable and conservative. In reality, the thermal conversion unit functions in a similar manner to a thermal oxidizer. Thermal oxidizers are routinely used to enhance destruction of NO_x, CO and SO_x emissions at other facilities. As a result, it is reasonable to assume that the thermal conversion unit will serve to help promote NO_x destruction during operation which would result in lower NO_2/NO_x ratios than modeled. In addition, the NO_2/NO_x in-stack ratio is not expected to vary based on operating conditions.

DEQ requested that, if available, NOx CEMs data with concurrent NO_2 to NO_x ratio analysis on a solid waste to energy facility be provided. Based on a search of publicly available data, WTE facility NO_2/NO_x ratio CEMs data could not be found. However, one reference was found which states that "the typical in-stack ratios for mass burn waste-to-energy units is 0.05" (Malcolm Pirnie, 2010)[1].

Sincerely,

Shannon Manoulian, P.E.

Enclosures

Cc: Dynamis Energy, LLC

1. Solid Waste Authority of Palm Beach County. Supplemental Air Quality Modeling Protocol for 1-hr NO2 and SO2 NAAQS, Palm Beach Renewable Energy Facility No. 2. Prepared by Malcolm Pirnie, Inc. Revised September 2010.

Dynamis Energy, LLC

Hidden Hollow Landfill WTE Facility
Air Quality Modeling Report

REVISED INFORMATION

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July 2012

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1.0 PURPOSE

This air quality modeling report documents the methodology used to prepare an air quality analyses in support of an Idaho Department of Environmental Quality (IDEQ) 15-Day Pre-Permit Construction (15-Day) application and subsequent Permit to Construct (PTC) application for the Dynamis Energy, LLC (Dynamis) Waste-To-Energy (WTE) facility at the Ada County Landfill in Ada County, ID (Appendix A). This report seeks to fully document and report the methods and techniques used to perform the modeling in support of Dynamis' 15-Day and PTC applications.

This air quality modeling report presents updated information regarding the methods, techniques and results of revised modeling based on discussion with DEQ. Updates have been made to previously submitted modeling analysis based on discussions between DEQ and JBR as outlined in the Response to Modeling Discussion Issues – July 3, 2012, submitted to DEQ via email on July 9, 2012. Information previously included in the appendices that has not been modified or updated (e.g. scrubber manufacturer guarantee) will not be included in this report.

2.0 PROCESS DESCRIPTION

The Dynamis WTE facility uses a proprietary thermal conversion technology process to convert municipal solid waste (MSW), including automobile tires, to energy. Dynamis' technology utilizes a controlled (starved) air gasification process which thermally converts waste products to combustible gas. The two-stage process provides complete conversion of carbon to an inert ash and a controlled heat output for efficient energy recovery.

2.1 General Process Overview

The two-stage waste to energy process uses batch waste gasification and thermal combustion/oxidation. MSW is initially loaded into a primary chamber where it is thermally reacted under air controlled (starved) conditions and transformed into burnable gases and ash. Unlike typical thermal treatment methods, the gasification reactions occur at relatively low temperatures under controlled conditions. This minimizes the production of airborne 'fly ash' particulates, carryover of toxic metals, and NO_x. The gasification process ensures nearly 100% destruction (burn-out) of the combustible waste and the by-product of ash is sterile with minimal residual carbon. Metals and glass in the waste stay with the ash in inert forms and can be recovered by conventional recycling methods. To complete the process, the gases from the primary gasification chamber enter the secondary combustion chamber where they are mixed with oxygen (taken from ambient air) and oxidized at high temperature to complete the process.

The energy from the hot gas effluent can then be recaptured for local heat, power or other forms of energy recovery.

Tipping Floor/Conveyor to Primary

The process begins by loading MSW, directly from garbage trucks, onto the tipping floor. Next the MSW is moved by conveyer into the primary gasification chamber. Waste materials can be accepted loose, bagged, baled, or on pallets. The system can also accept a wide range of bulky items such as vehicle tires, mattresses, furniture, and construction debris.

The Primary Gasification Chamber (PGC)

The MSW is then bulk-loaded into the primary gasification chamber (PGC) through a hydraulically operated door at the top or front of the chamber and a carefully controlled flow of air is introduced. Only enough air is provided to allow sufficient burning for heating to occur, typically 70 to 80 percent of the stoichiometric air requirement is introduced into the PGC. Due to the air controlled (starved) environment, the MSW gasifies and is converted to a super rich gas. Gasification occurs in the PGC at relatively low temperatures of 450-550°C (800-1000°F), converting the waste into gas and ash. The hot gases are then passed to the secondary combustion system.

The Secondary Combustion System (SCS)

Once the hot gas is passed into the secondary combustion system (SCS) they are actively mixed with oxygen (taken from the ambient air). This process is achieved by the use of a turbulent air ring which flashes (combusts) the mixture at temperatures of 1,800-2,000°F. The turbulent air ring and temperature assure that a rapid and thorough mixture of the super rich gas and oxygen is achieved. Combustion gases are maintained at temperatures of 1,800-2,000F for an extended retention time prior to entering a heat recovery steam generator. This insures all combustible gases are consumed.

Boiler/Steam Production

The flame created by the super rich gas/oxygen combustion is directed through a high temperature power boiler where water is converted into high pressure steam. The boiler has an extended retention time design that provides maximum furnace volume without excessive refractory, plus increased radiant surface for maximum heat absorption.

Energy Production

This high pressure steam generated from the boiler is directed through a power generation turbine creating electrical power that can be routed to the local electrical grid.

Process Logic Control System

All aspects of combustion and fuel feed are monitored and controlled by state-of-the-art logic, 3 times per second. This is especially important with the ever-changing combustion conditions of biomass and waste fuels. The microprocessor analyzes data from various inputs such as switches, thermocouples, RTDs and an oxygen sensor to continually monitor exhaust and optimize air-to-fuel mixture, and signal when anything needs attention.

Ash Handling

Recyclables and ash from the process are collected for reclamation. After each gasification cycle in the PGC the remaining material (approximately 10% of the original volume) will be moved by conveyor belt to the ash handling system, where all recyclables are sorted and retained automatically. The end by-product of the gasification process is inert ash, which will be collected and possibly sold as an important additive in concrete and cement based building materials.

2.2 Hidden Hollow WTE Facility

The Dynamis WTE facility at the Hidden Hollow Landfill will consist of one thermal conversion unit, capable of processing up to 408 tons per day (tpd) of MSW, including automobile tires. The MSW will be delivered to the facility and dumped on the tipping floor inside the facility building. The waste is then conveyed to one of twelve primary gasification chambers in the thermal conversion unit. The system will operate as a batch process with each primary gasification chamber being loaded in succession. The super rich gas created in each of the primary gasification chambers is passed into the secondary combustion chamber where it is mixed with oxygen creating a flame. The flame is directed through a high temperature power boiler where water is converted into high pressure steam. The high pressure steam generated from the boiler is directed through a power generation turbine creating electrical power.

Per the contract between Dynamis and Idaho Power, Dynamis will provide 22 MW of power to Idaho Power continually during peak hours (7am to 11pm). Based on system design, and estimated fuel heat value, this will be achieved by operating the system consistent with the temperatures and exhaust flow rates indicated in the modeling analysis for the UNITPEAK operation. The system will be ‘turned down’ between the hours of 11pm and 7am, such that it will continue to run, however, power generated during these hours will be used to power the facility. Due to the contracted power output requirements, Dynamis does not reasonably expect to operate the facility at any other level of operation greater or less than already modeled

Ash produced in the primary gasification chamber is collected in bins beneath the chambers. The ash is moved by conveyor belt to the ash handling system, where the material is conveyed

through a roller drum magnet to separate ferrous metals from the ash. Ferrous metals collected in the roller drum magnet are collected in the ferrous metals storage bin. The remaining ash material then passes through an eddy current pulse separator, which removes any aluminum from the ash. Aluminum material then travels via conveyor to the aluminum storage bin; clean ash material is transferred via conveyor to the clean ash storage bin. The ash handling system is completely enclosed. In addition, a baghouse is used to control particulate emissions during material separation and handling in the ash handling room.

3.0 MODEL DESCRIPTION/JUSTIFICATION

The model used for this application is AERMOD (version 12060), the USEPA–approved model for near-field new source review. Based on EPA guidance AERMOD is the most appropriate of the EPA-approved models given the site's physical characteristics and the facility emission sources. AERMOD was applied as recommended in EPA's Guideline on Air Quality Models and consistent with guidance in IDEQ's Dispersion Modeling Guidelines. Non-regulatory default options were employed; specifically the Ozone Limiting Method (OLM) was employed for modeling 1-hr NO_2 impacts. This is discussed further below.

The Prime building downwash algorithm was applied for the facility. Terrain data was processed consistent with the modeling protocol submitted to DEQ and EPA guidance for AERMAP. Meteorological data recommended for this analysis was provided by IDEQ. IDEQ requires modeling of criteria pollutants if emissions from the proposed source exceed the modeling thresholds set forth the IDEQ Dispersion Modeling Guidelines.

The criteria pollutants which exceed the modeling threshold at the Dynamis WTE facility are PM_{10}, $PM_{2.5}$, NO_x, SO_2 and Pb. In addition, benzene, cadmium, dioxin, formaldehyde, hydrogen chloride, mercury and nickel exceed the TAPs screening emission levels (ELs) in IDAPA 58.01.01.585 and 586. The Dynamis facility will be subject to 40 CFR Part 60 Subpart Eb - Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996. Emissions of dioxin, cadmium, hydrochloric acid and mercury are regulated under NSPS Subpart Eb. IDAPA 58.010.01, Subsection 210.20 (a) states the following:

> *"If the owner or operator demonstrates that the toxic air pollutant from the source or modification is regulated by the Department at the time or permit issuance under 40 CFR Part 60, 40 CFR Part 61, or 40 CFR Part 63, no further procedures for demonstrating preconstruction compliance will be required under Section 210 for that toxic air pollutant as*

part of the application process."

Therefore, dioxin, cadmium, hydrochloric acid and mercury were not included in the modeling analysis.

In general, the AERMOD model application used model source data consistent with the permit emission inventory. The model receptor network and model domain proposed meet all EPA and IDEQ recommendations, and ensure a complete dispersion analysis that captured maximum potential impacts.

3.1 Non-Regulatory Defaults

As discussed above, the Ozone Limiting Method (OLM) was used to demonstrate compliance with 1-hr NO_2 impacts. The OLM was employed as recommended in the June 28, 2010 Memorandum to EPA Regional Air Division Directors from Stephen D. Page, Director EPA Office of Air Quality Planning and Standards, titled "Guidance Concerning the Implementation of the 1-hr NO_2 NAAQS for the Prevention of Significant Deterioration Program" and IDEQ modeling protocol approval. The OLM requires in-stack ratios of NO_2/NO_x emissions as well as hourly monitored background ozone (O_3) concentrations. The NO_2/NO_x in-stack ratio of 0.15 for the thermal conversion unit was conservatively based on a blend of in-stack ratios for natural gas and diesel generator emissions as found in "Assessment of Non-Regulatory Options in AERMOD, Specifically OLM and PVMRM" from the San Joaquin Valley Air Pollution Control District In reality, the thermal conversion unit functions in a similar manner to a thermal oxidizer. Thermal oxidizers are routinely used to enhance destruction of NO_x, CO and SO_x emissions at other facilities. As a result, it is reasonable to assume that the thermal conversion unit will serve to help promote NO_x destruction during operation which would result in lower NO_2/NO_x ratios than modeled. An in-stack NO_2/NO_x ratio of 0.20 was used for the Dynamis emergency diesel generator (San Joaquin Valley Air Pollution Control District guidance). Per DEQ and EPA guidance, 0.90 was used as the default equilibrium NO_2/NO_x ratio for the 1-hr NO_2 standard. For modeling runs including co-contributing sources, an in-stack NO_2/NO_x ratio of 0.15 was used for the thermal conversion unit, an in-stack ratio of 0.20 was used for the Dynamis emergency generator and ACLF generators (based on in-stack ratios for diesel internal combustion engines found in the San Joaquin Valley guidance document), and the default ratio of 0.50 was used for all other sources. Also as recommended in EPA guidance, the OLMGROUP ALL option was employed.

In addition to the NO_2/NO_x ratio, hourly background O_3 concentrations are required for the OLM analysis. Hourly ozone data was provided by DEQ. The ozone backgrounds were developed

using the 98th percentile value of hourly monitoring data from 2009, 2010, and 2011 from the White Pine site, in southeastern Boise, near the intersection of Boise Avenue and Apple Street.

4.0 EMISSION AND SOURCE DATA

Modeled emissions include all sources of PM_{10}, $PM_{2.5}$, NO_x SO_2, Pb, Benzene, Formaldehyde, and Ni. Emission rates represent the maximum anticipated operating rates for the averaging period modeled, taking into account the maximum daily hours of operation and throughputs requested in the application for all averaging periods.

Table 1 below compares the facility's Potential to Emit (PTE) for all criteria pollutants against IDEQ Modeling Thresholds. Table 2 compares the facility's PTE for those Toxic Air Pollutants (TAPs) that exceed the emissions screening levels in IDAPA 58.01.01.585 and 586. Emission summaries are documented in more detail in the facility's emission inventory.

Table 1 Project Potential Criteria Pollutant Emissions vs. IDEQ Modeling Thresholds

Criteria Modeling Check	PM_{10}	$PM_{2.5}$	NO_X	SO_2	CO	Pb*
Controlled Emission Rates, lb/hr (tpy)	4.72 (13.6)	4.72 (13.6)	22.2 (57.8)	10.8 (27.0)	13.2 (34.2)	26.2
Modeling Threshold, lb/hr (tpy)	0.22 (n/a)	0.054 (0.35)	0.2 (1.2)	0.21 (1.2)	15 (n/a)	14
Modeling Required:	YES	YES	YES	YES	NO	YES

*Pb emission rate and modeling threshold are in lb/month

Table 2 Project Potential TAPs Emissions vs. IDEQ Modeling Thresholds

TAPs Modeling Check	Benzene	Formaldehyde	Nickel
Controlled Emission Rates (lb/hr)	1.2E-03	1.8E-03	1.5E-2
Screening Emission Level (lb/hr)	8.0E-04	5.1E-04	2.7E-05
Modeling Required:	YES	YES	YES

4.1 Emissions Sources

Emissions sources at the facility include the following:

Thermal Conversion Units

Dynamis will operate one 408 tpd thermal conversion unit at the facility. The unit consists of the primary gasification chamber, secondary combustion chamber, and boiler. Steam generated in the boiler is used to power a power generation turbine. Emissions from the primary gasification chambers and secondary combustion chambers are exhausted through the boiler stack. The boilers will be custom made for the facility by Victory Energy. The majority of MSW, 380 tpd, will be processed between the hours of 7am and 11pm (16 hours). The remaining MSW, 28 tpd, will be processed between 11pm and 7am. Emissions rates and model sources used in the modeling analysis will reflect both the peak and off-peak operation, for those pollutants with averaging periods less than 24 hrs (1-hr NO_x and 1-hr SO_2). The facility will process 408 total tons of MSW per day. The MSW is expected to contain moisture as well as un-combustible materials such as glass and metal. It is conservatively assumed that 90% of the MSW received will be combustible materials; therefore, emissions estimates are based on 367 tpd of combustible material (342 tpd peak, 25 tpd off-peak).

The thermal conversion unit is a source of PM_{10}, $PM_{2.5,}$ NO_x, SO_2, CO, Lead, and TAPs. Emission factors for the thermal conversion unit were developed using source test data from similar units installed at other facilities in the United States. Emissions from the thermal unit (including primary chamber ignition system natural gas combustion) will be controlled by a scrubber located between the boiler and exhaust stack. The scrubber has a manufacturer guaranteed emission rate 0.595 lb/hr HCl, 71.25% control of SO_2, 99% control of PM_{10}, and 90% control of particulate sized 1.5 to 2.5 micron (this equates to approximately 41% control of $PM_{2.5}$; it is estimated that particulates sized 1.5 to 2.5 micron comprise approximately 46% of $PM_{2.5}$ from gasification). The scrubber manufacturer guarantees 41% control of $PM_{2.5}$ and smaller, with higher control efficiency expected for larger particulates. Metals emissions (with the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals. Manufacturer guarantee information sheets are included in Appendix B.

In addition, the thermal conversion unit will be equipped with a urea-based Selective Non-Catalytic Reduction (SNCR) device to reduce NO_x. The SNCR manufacturer has guaranteed NO_x reduction of at least 40%, based on incoming loading of up to 50 lb/hr NO_x. Manufacturer guarantee information is included in Appendix B.

Primary Gasification Chamber Ignition System

Each time waste is loaded into the primary gasification chamber and the chamber is lit, a small amount of fuel is required to ignite the chamber burner. The ignition system will be fueled by natural gas. A total of 112,000 scf/day of natural gas will be used for all ignition systems. The primary gasification chamber ignition system will exhaust through the primary and secondary chambers and out of the boiler exhaust stack (and will be controlled by the scrubber and SNCR). The ignition system is a source of PM_{10}, $PM_{2.5}$, NO_x, SO_2, CO, VOCs, and TAPs. Emission factors from AP-42, Section 1.4 were used to calculate natural gas combustion emissions.

Cooling Towers

Steam exiting the turbine will be exhausted through a condenser that is cooled with water from two cooling towers. Water used in the cooling towers will be supplied by United Water. The cooling towers are a source of PM_{10} and $PM_{2.5}$. Emissions factors from AP-42 Section 13.4 and input water analysis TDS content were used to calculate cooling tower particulate emissions.

Ash Handling System

As discussed above, the ash collection system consists of various conveyors, ferrous and aluminum material separators and collection bins. A total of five dust collection units will control PM_{10}/$PM_{2.5}$ emissions from the ash handling system. The dust collectors are centrally located in the ash handling room above the roller drum magnet and eddy current pulse separator to collect any dust generated during ash material separation and above the ferrous material, aluminum material and clean ash bins. The dust collectors will discharge to the ash system baghouse, which has a manufacturer guaranteed emission rate of 0.005 grains/dscf for particles size 10 micron and smaller. The baghouse will exhaust through a stack outside of the ash handling room, and will exhaust for approximately 45 minutes every hour. The ash handling system is a source of PM_{10}, $PM_{2.5}$ and TAPs. Ash testing data (TCLP mg/L results) was converted to an approximate mg/kg concentration to develop emission factors for pollutant emissions from the ash system. Specifications on the baghouse are included in Appendix B.

Emergency Generator

The facility will be powered by electric line power. However, a 300 kW emergency diesel generator will be installed at the facility. The proposed generator will be an EPA Tier III certified Caterpillar C9 ACERT (or similar), and will run no more than 500 hours per year. The generator will only be tested once per quarter and testing will occur between 7 am and 7 pm. The MHRDOW7 – Monthly by Hour by Day of Week emission rate factor was employed for the generator in AERMOD. One day each quarter was randomly selected for testing. However, the MHRDOW7 simulates testing on every selected day that occurs in the month selected. Therefore, air dispersion modeling results represent impacts that would occur as if the generator

was tested 4 days per quarter. This results in conservative estimates of impacts from the generator. The emergency generator is a source of PM_{10}, $PM_{2.5}$, NO_x, SO_2 CO, VOCs, and TAPs. Manufacturer data and emission factors from AP-42 Section 3.3 were used to calculate generator emissions estimates. Manufacturer data is included in Appendix B.

Emissions factors for the thermal conversion unit and ash handling system used to develop the emissions inventory are based on multiple source tests of similar thermal conversion units installed at various facilities over the past 15 years. Source tests were previously provided to DEQ, but will be provided again if requested.

Cooling tower, emergency generator, and primary gasification ignition system fuel combustion emissions estimates were developed using manufacturer data and AP-42. A detailed emissions inventory for each emissions source is provided with the permit application and in Appendix C of this report. DEQ forms are provided in Appendix D.

JBR performed an initial Significant Impact Level (SIL) analysis which included only sources from the Dynamis facility and the lease boundary as the ambient air boundary. Impacts from the Dynamis WTE facility exceed the IDEQ SILs for 24-hr and annual $PM_{2.5}$, 24-hr PM_{10}, and 1-hr and Annual NO_x and SO_2. SIL model results are shown in Table 4 below. Receptors for each pollutant and averaging period exceeding the SIL were used to perform a full impact analysis, including co-contributing sources. Excel files containing the coordinates and elevations of receptors above the SILs are included in Appendix E.

As part of the modeling protocol JBR requested, and DEQ provided, exhaust parameters and emission rates for neighboring facilities that DEQ deemed to be co-contributing sources. DEQ determined that the Hidden Hollow Energy, LLC (HHE) facility and Ada County Landfill (ACLF) are co-contributing sources for the Dynamis facility. Emissions points at the Hidden Hollow Energy facility include four internal combustion generator engines; emissions points at the Ada County Landfill include two generators and two landfill gas flares. In the modeling protocol approval received from DEQ (included as Appendix F) DEQ provided exhaust parameters and emission rates for two operating scenarios for the HHE engines and ACLF sources. Ambient air boundary information for the HHE facility and ACLF were provided via email from Cheryl Robinson, DEQ.

5.0 RECEPTOR NETWORK

The Dynamis WTE facility is located just outside of the city of Boise and is bordered by residential development to the east and west. The property covers approximately 8.0 acres.

Consistent with IDEQ guidance the ambient air boundary used in this analysis is the lease boundary and controlled easement area, which also serves as the public access boundary. Dynamis will control access to the leased property and controlled easement area through posting of signage and by training facility personnel to patrol and prevent public access. Access to the area south of the facility is also limited by terrain. In addition, Dynamis will ensure that Ada County Landfill employees understand that the facility is property of Dynamis, and access is restricted to anyone other than Dynamis personnel or invited guests.

Receptor density was set at a spacing of 10 meters along the ambient air boundary, 20 meter spacing for the first 30 meters past the boundary, then receptors were set at a density of one per 35 meters out to 60 meters away from the property boundary, 50 meters out to 100 meters from the boundary, 100 meters to 500 meters, 250 meters out to 2,000 meters from the ambient air boundary, and 500 meters out to 50 kilometers past the ambient air boundary. The receptor network ensures that all impacts above the respective SILs were captured. In addition, receptors were added near locations of maximum impacts to ensure the true maximum impacts were captured. These receptors were added by constructing a 200 meter by 200 meter grid surrounding the area of maximum impact, with receptor spacing of 20 meters within the grid. The receptor network used ensures that the analysis meets or exceeds EPA receptor network requirements and captures the maximum impact from the facility. The receptor networks used for the full impact analyses are discussed in detail in Section 10.3.

6.0 ELEVATION DATA

Receptor elevations were initially calculated from USGS 1/3 arc second NED data using the Bee-Line BEEST preprocessing system. The QUADDATE (the most recent revision date) of the NED data for the areas covering the receptor network ranges from 1999 to 2002. Based on a review of historical images in Google Earth, significant grading, road construction and topographical changes occurred at the landfill between 2002 and the present. Imagery shown in Google Earth is from 2011; however, elevations given by Google Earth appear to be consistent with the 2002 NED data elevations.

JBR used the Dynamis site grading plan to manually adjust receptor elevations where data is available in the immediate vicinity of the Dynamis property, as shown on the plan. Updated grading information for the landfill property is not available; therefore, the NED elevations were not adjusted for receptors outside of the extent of the Dynamis grading plan. The exception to this is where the NED receptor elevation of a receptor adjacent to an adjusted Dynamis receptor differed by more than 25 feet. These instances were addressed on a case-by-case basis, and the NED elevation was adjusted in order to ‘smooth’ the transition between receptors. This was

done to ensure that no plume impacts were missed due to a large discrete receptor elevation change.

All source base elevations were calculated based on the site grading plan and finished floor elevations for the property. All stack heights were referenced to re-graded ground surface elevations.

7.0 METEOROLOGICAL DATA

Preprocessed AERMOD ready meteorological files were provided upon request from Darrin Mehr of IDEQ. The data was processed by ENVIRON, using National Weather Service surface data observations and upper air data observations from the Boise, Idaho Airport for the period 2005-2009. In addition to the hourly NWS data, 1-minute wind speed and wind direction data from Boise Airport were used to resolve calm and variable wind conditions using the AERMINUTE preprocessor. The data files cover the years 2005 through 2009. The data presented by IDEQ is model-ready, and was used without alteration or processing.

8.0 LAND USE CLASSIFICATION

AERMOD includes rural and urban algorithm options. These options affect the wind speed profile, dispersion rates, and mixing-height formula used in calculating ground-level pollutant concentrations. A protocol was developed by USEPA to classify an area as either rural or urban for dispersion modeling purposes. The classification is based on average heat flux, land use, or population density within a three-km radius from the plant site. Of these techniques, the USEPA has specified that land use is the most definitive criterion (USEPA, 1987). The urban/rural classification scheme based on land use is as follows:

> *The land use within the total area, A_0, circumscribed by a 3-km circle about the source, is classified using the meteorological land use typing scheme proposed by Auer (1978). The classification scheme requires that more than 50% of the area, A_0, be from the following land use types in order to be considered urban for dispersion modeling purposes: heavy industrial (I1); light-moderate industrial (I2); commercial (C1); single-family compact residential (R2); and multi-family compact residential (R3). Otherwise, the use of rural dispersion coefficients is appropriate.*

The Dynamis WTE facility is located just outside of the city of Boise and is bordered by residential development to the east and west. Although the immediate vicinity of the site is residential, site and map reconnaissance showed that the area A_0 within a 3-km circle of the

source is below the 50% urban land use criteria necessary for use of urban dispersion coefficients. Rural dispersion coefficients were therefore used in the air quality dispersion modeling.

9.0 BACKGROUND CONCENTRATIONS

Background concentrations for criteria pollutants as provided by IDEQ are shown in Table 3 below. Background values for TAPs are zero.

Table 3 Background Concentrations

Pollutant	Averaging Period	Background Concentration (ug/m3)	Source
PM_{10}	24-hour	73	Historical DEQ airshed modeling for the Boise Area; intended to represent the background at the landfill.
$PM_{2.5}$	24-hr	19.3	Meridian, Idaho monitor 2008, 2009, and 2010 finalized data from the U.S. EPA AirData website. The 24-hr average background is the 3-year average of each year's 98th percentile value.
	Annual	6.3	Meridian, Idaho monitor 2008, 2009, and 2010 finalized data from the U.S. EPA AirData website. The annual average background is the 3-year average of the weighted mean value for each year.
NO_2	1-hr	Variable	Hourly background concentrations based on 2007 and 2010 data from the ITD monitoring site in Boise. Values are the 98th percentile values for each hour during a day.
	Annual	40	Boise monitoring data
SO_2	1-hr	33.1	Fargo ND/Moorhead MN monitoring data, 2006-2008, 1st high value plus one standard deviation of values meeting 75% completeness criteria
	Annual	2.6	Fargo ND/Moorhead MN monitoring data, 2004-2008, all non-zero values meeting 75% completeness criteria are 0.001ppm = 2.6 ug/m^3
Pb	Rolling 3-month average	0.04	Default: Urban>45,000

10.0 MODEL RESULTS AND DISCUSSION

As stated above, JBR performed both a SIL analysis for the Dynamis facility and full impact analysis including the HHE facility and ACLF as co-contributing sources. Results of the SIL

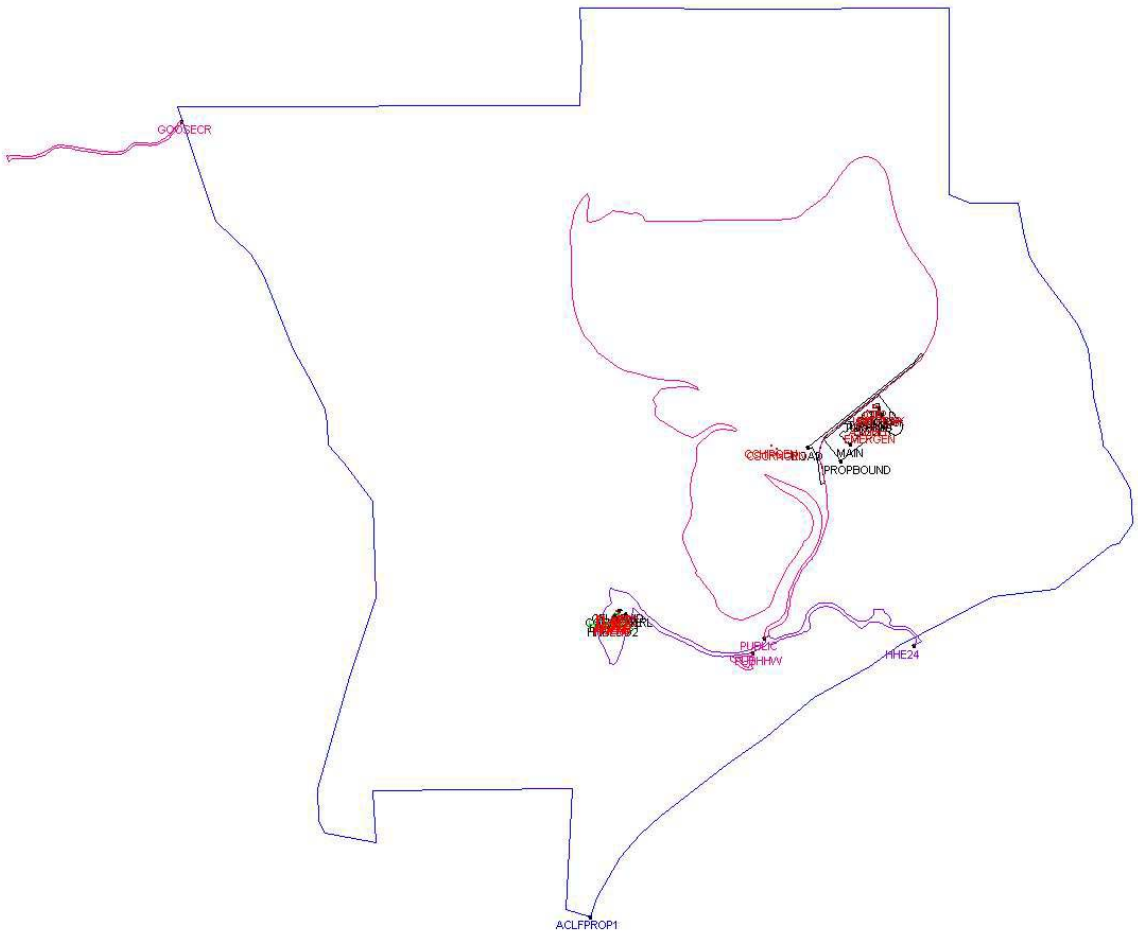
analysis are shown in Table 4. Per DEQ guidance, the 1st high output value and a concatenated 5-year met file were used for 24-hr PM_{10}, 24-hr $PM_{2.5}$, annual $PM_{2.5}$, 1-hr NO_2, 1-hr SO_2, 24-hr TAPs and annual TAPs. The highest 1st high output value from five separate meteorological year runs was used for annual NO_2 and annual SO_2.

Table 4 SIL Model Predicted Impacts – Dynamis Facility SIL Analysis

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	SIL (ug/m^3)	NAAQS/ AAC/AACC (ug/m^3)	Modeled Output Value Used (5 years met data)	Met Data Used
PM_{10}	24-hour	10.8	5.0	150	1st high	5-yr concatenated
$PM_{2.5}$	24-hr	8.62	1.2	35	1st high	5-yr concatenated
	Annual	1.63	0.3	15	1st high	5-yr concatenated
NO_2	1-hr	142	7.5	188	1st high	5-yr concatenated
	Annual	9.05	1.0	100	1st high	One met file for each year of data
SO_2	1-hr	93.7	7.9	196	1st high	5-yr concatenated
	Annual	2.49	1.0	80	1st high	One met file for each year of data
Pb	Rolling 3-month average	0.017	n/a	0.15	1st high	5-yr concatenated
Benzene	Annual	1.0E-5	n/a	1.2E-01	1st high	5-yr concatenated
Formaldehyde	Annual	9.0E-5	n/a	7.7E-02	1st high	5-yr concatenated
Nickel	Annual	3.98E-3	n/a	4.2E-03	1st high	5-yr concatenated

Receptors exceeding the SIL for each pollutant and averaging period were used as the receptors for the full impact analysis. Annual NO_x values from the SIL analysis were multiplied by 0.75 and then compared to the SIL to determine receptors to use for the full impact analysis. DEQ provided exhaust parameters and emission rates for two operating scenarios for the HHE facility and ACLF sources. Ambient air boundaries for HHE and the ACLF were also provided by DEQ and are shown in Figure 1.

Figure 1 Ambient Air Boundaries - Dynamis, HHE Facility and ACLF



Pink lines define areas where the general public will have access when the landfill is open (typically 7 am to 7 pm). Purple lines define areas where Hidden Hollow Energy employees (members of the public for Dynamis modeling) will typically have access 24 hours per day. Blue lines define the outer boundary of the ACLF property. Black lines (not including the road outlined in black) define the Dynamis property boundary. Ambient impacts caused by each of the three facilities with each facility's ambient air boundary are not evaluated for compliance with the NAAQs; a facility cannot cause or contribute to a NAAQs exceedance within its own ambient air boundary.

10.1 Operating Scenario 1

HHE will be assumed to operate four generator engines with 2,400 standard cubic feet per minute (scfm) of landfill gas limited to an H2S content of 180 parts per million by volume (ppmv). The HHE generators each operate 24 hours per day and 8760 hours per year. The ACLF flaring operations will be assumed to operate at 950 scfm of landfill gas combusted in one flare. The ACLF flare will operate 24 hours a day, 8760 hours per year. The ACLF Wood Chipper and Power Screen Engines were assumed to both operate 24 hours per day and 3,300 hours per year. Emission rates for HHE and ACLF sources for operating scenario 1 are shown in Table 5 below.

Table 5 Co-Contributing Source Emission Rates: Scenario 1

Emission Rates: Scenario 1						
Source	**$PM_{10}/PM_{2.5}$**		**SO_2**		**NO_x**	
	(lb/hr)	**(T/yr)**	**(lb/hr)**	**(T/yr)**	**(lb/hr)**	**(T/yr)**
Hidden Hollow Energy Sources						
Generator Engine 1	0.78	3.42	1.09	4.77	2.46	10.77
Generator Engine 2	0.78	3.42	1.09	4.77	2.46	10.77
Generator Engine 3	0.78	3.42	1.09	4.77	2.46	10.77
Generator Engine 4	0.78	3.42	1.09	4.77	2.46	10.77
Ada County Landfill Sources						
Flare 1	0.92	4.02	5.78	25.30	1.75	7.65
Chipper Engine	0.30	0.50	0.008	0.01	5.36	8.84
Power Screen Engine	0.27	0.44	0.001	0.002	3.79	6.25

10.2 Operating Scenario 2

Operating scenario 2 assumes that the HHE generators are non-operational and ACLF is combusting 3,350 scfm of landfill gas at 600 ppmv of H_2S. The landfill gas is split evenly

between the two flares, which are assumed to each operate 24 hours per day, 8760 hours per year. The Wood Chipper and Power Screen engines are assume to operate at full capacity 24 hours per day, 3,300 hours per year. Emission rates for ACLF sources for operating scenario 2 are shown in Table 6 below.

Table 6 Co-Contributing Source Emission Rates: Scenario 2

Emission Rates: Scenario 2						
Source	**$PM_{10}/PM_{2.5}$**		**SO_2**		**NO_x**	
	(lb/hr)	**(T/yr)**	**(lb/hr)**	**(T/yr)**	**(lb/hr)**	**(T/yr)**
Ada County Landfill Sources						
Flare 1	1.62	7.08	10.19	44.61	3.08	13.49
Flare 2	1.62	7.08	10.19	44.61	3.08	13.49
Chipper Engine	0.30	0.50	0.008	0.01	5.36	8.84
Power Screen Engine	0.27	0.44	0.001	0.002	3.79	6.25

10.3 Full Impact Analysis Model Ambient Boundaries and Receptors

A total of 16 model runs were setup for each of the two co-contributing source operating scenarios. The model runs were based on the receptors above the SIL for each pollutant and averaging period above the SIL within each of the three ambient air boundary scenarios. The three ambient air boundary scenarios include the following:

- "7AM to 7PM" in which the public has access to certain areas of the landfill, and therefore ACLF sources can contribute to a NAAQs exceedance within the public access boundary inside the larger ACLF property boundary. Dynamis and HHE sources can also contribute to a NAAQs exceedance within this boundary.
- "Night" in which the public does not have access to any areas with the ACFL boundary and therefore ACLF sources cannot contribute to a NAAQs exceedance anywhere within the ACLF property boundary. Only Dynamis and HEE sources can contribute to a NAAQs exceedance within this boundary.
- "Out" scenario includes all receptors outside the larger ACLF property boundary. Dynamis, HHE and ACLF sources can contribute to a NAAQs exceedance outside of this property boundary.

It should be noted that there were no Dynamis receptors above the SIL for any pollutant or averaging period located within the HHE property boundary.

Receptors above the SIL for each pollutant and averaging period and ambient air boundary are shown in Figures 2 to 4 below.

Figure 2 "7AM -7PM" Receptors

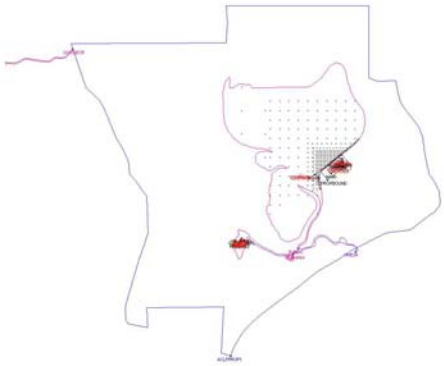
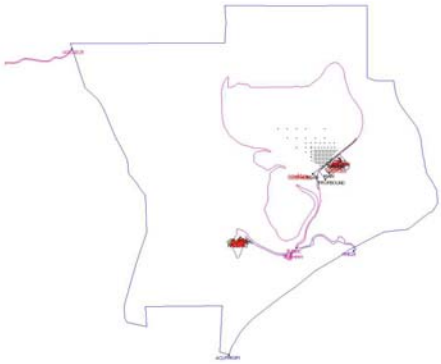
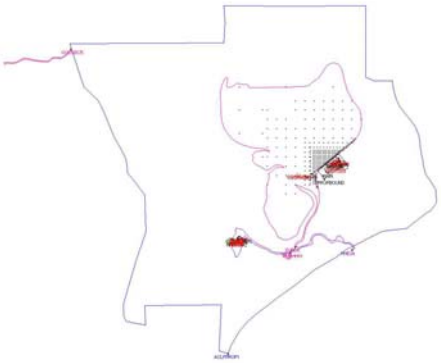
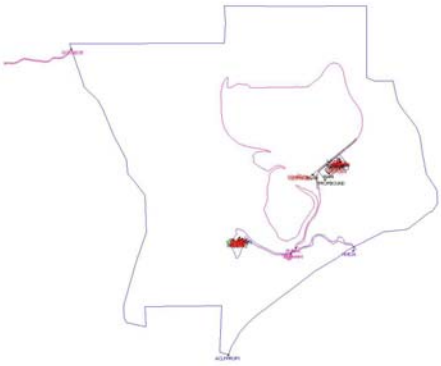
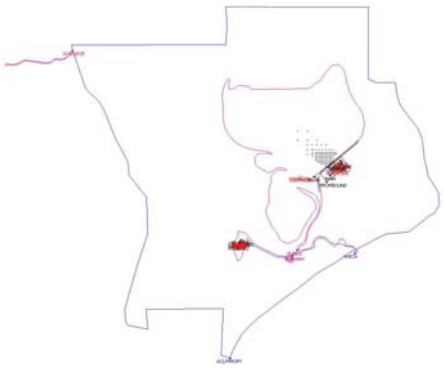
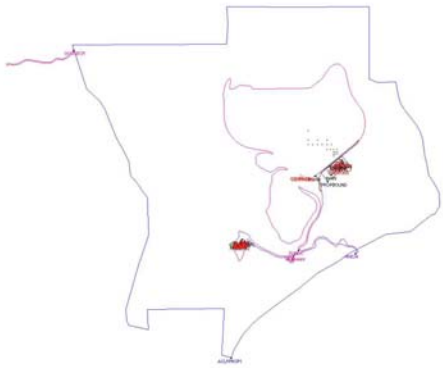
	
1-hr NO_x Receptors	24-hr $PM_{2.5}$ Receptors
	
1-hr SO_2 Receptors	24-hr PM_{10} Receptors
	
Annual $PM_{2.5}$ receptors	Annual SO_2 and NO_x receptors

Figure 3 "Night" Receptors

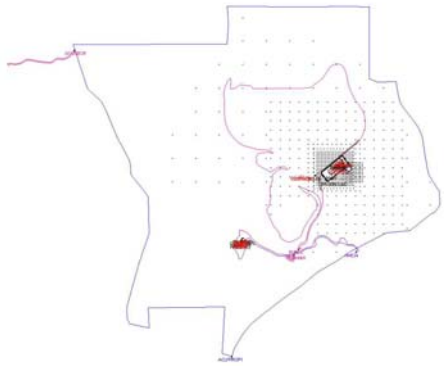
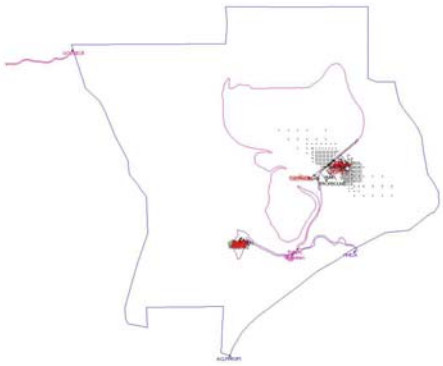
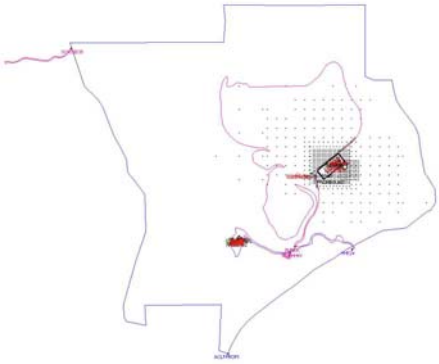
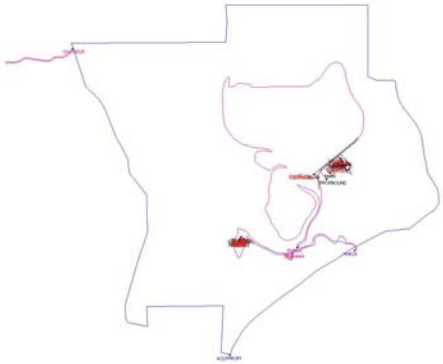
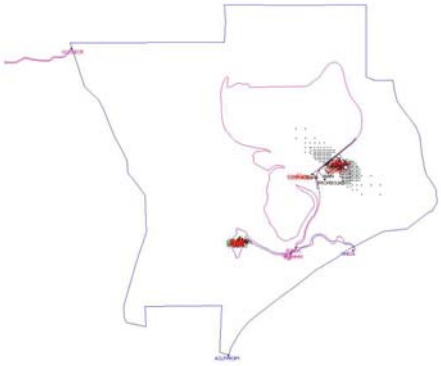
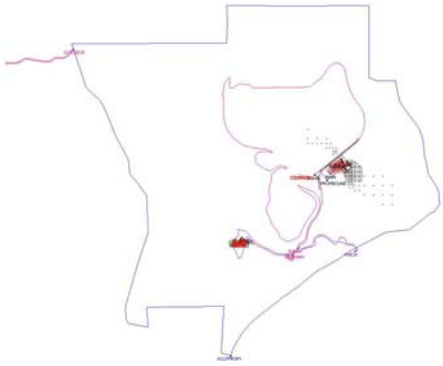
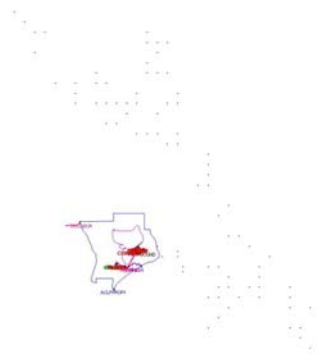
	
1-hr NO_x Receptors	24-hr $PM_{2.5}$ Receptors
	
1-hr SO_2 Receptors	24-hr PM_{10} Receptors
	
Annual $PM_{2.5}$ receptors	Annual SO_2 and NO_x receptors

Figure 4 "Out" Receptors

	
1-hr NO_x Receptors	1-hr SO_2 Receptors

10.4 Full Impact Analysis Model Runs

A total of 16 model runs were setup for each of the two co-contributing source operating scenarios, based on the combination of ambient air boundaries listed above, receptors above the SIL within those boundaries, and sources which could contribute to an exceedance of the NAAQs at those receptors. The model runs are summarized in Table 7 below.

Table 7 Full Impact Analysis Model Run Summary

Operating Scenario	Pollutant	Averaging Period	Model Name	Description
Scenario 1	NOx	1-hr	ALL_S1_NO2_r3_7AP	Receptors exceeding 1-hr NOx SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis, HHE and ACLF (ACLF sources operating 7am to 7pm only).
	NOx	1-hr	ALL_S1_NO2_r3_NIGHT	Receptors exceeding 1-hr NOx SIL within the ACLF boundary (blue outline). Sources include Dynamis and HHE.
	NOx	1-hr	ALL_S1_NO2_r3_OUT	Receptors exceeding 1-hr NOx SIL outside the ACLF boundary. Sources include Dynamis HHE, and ACLF.
	SO_2	1-hr	ALL_S1_SO2_r3_7AP	Receptors exceeding 1-hr SO_2 SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis, HHE and ACLF (ACLF sources operating 7am to 7pm only).
	SO_2	1-hr	ALL_S1_SO2_r3_NIGHT	Receptors exceeding 1-hr SO_2 SIL within the ACLF boundary (blue outline). Sources include Dynamis and HHE.
	SO_2	1-hr	ALL_S1_SO2_r3_OUT	Receptors exceeding 1-hr SO_x SIL outside the ACLF boundary. Sources include Dynamis HHE, and ACLF.
	$PM_{2.5}$	24-hr	ALL_S1_PM2.5_r3_7AP	Receptors exceeding 24-hr $PM_{2.5}$ SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis, HHE and ACLF (ACLF sources operating 7am to 7pm only)
	$PM_{2.5}$	24-hr	ALL_S1_PM2.5_r3_NIGHT	Receptors exceeding 24-hr $PM_{2.5}$ SIL within the ACLF boundary (blue outline). Sources include Dynamis and HHE
	PM_{10}	24-hr	ALL_S1_PM10_r3_7AP	Receptors exceeding 24-hr PM_{10} SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis, HHE and ACLF (ACLF sources operating 7am to 7pm only)
	PM_{10}	24-hr	ALL_S1_PM10_r3_NIGHT	Receptors exceeding 24-hr PM_{10} SIL within the ACLF boundary (blue outline). Sources include Dynamis and HHE.
	$PM_{2.5}$	Annual	ALL_S1_PM2.5ANN_r3_7AP	Receptors exceeding Annual $PM_{2.5}$ SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis, HHE and ACLF (ACLF sources operating 7am to 7pm only)
	$PM_{2.5}$	Annual	ALL_S1_PM2.5ANN_r3_Night	Receptors exceeding Annual $PM_{2.5}$ SIL within the ACLF boundary (blue outline). Sources include Dynamis and HHE
	NO_x, SO_2	Annual	ALL_S1_NOSOAN_r3_7AP	Receptors exceeding Annual NO_x and SO_2 SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis, HHE and ACLF (ACLF sources operating 7am to 7pm only).
	NO_x, SO_2	Annual	ALL_S1_NOSOAN_r3_NIGHT	Receptors exceeding Annual NO_x and SO_2 SIL within the ACLF boundary (blue outline). Sources include Dynamis and HHE.
Scenario 2	NOx	1-hr	ALL_S2_NOx_r3_7AP	Receptors exceeding 1-hr NOx SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis and ACLF (ACLF sources operating 7am to 7pm only).
	NOx	1-hr	ALL_S2_NOx_r3_NIGHT	Receptors exceeding 1-hr NOx SIL within the ACLF boundary (blue outline). Sources include Dynamis.
	NOx	1-hr	ALL_S2_NOx_r3_OUT	Receptors exceeding 1-hr NOx SIL outside the ACLF boundary. Sources include Dynamis and ACLF.
	SO_2	1-hr	ALL_S2_SO2_r3_7AP	Receptors exceeding 1-hr SO_2 SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis and ACLF (ACLF sources operating 7am to 7pm only).
	SO_2	1-hr	ALL_S2_SO2_r3_NIGHT	Receptors exceeding 1-hr SO_2 SIL within the ACLF boundary (blue outline). Sources include Dynamis.
	SO_2	1-hr	ALL_S2_SO2_r3_OUT	Receptors exceeding 1-hr SO_x SIL outside the ACLF boundary. Sources include Dynamis and ACLF.
	$PM_{2.5}$	24-hr	ALL_S2_PM2.5_r3_7AP	Receptors exceeding 24-hr $PM_{2.5}$ SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis and

				ACLF (ACLF sources operating 7am to 7pm only)
	$PM_{2.5}$	24-hr	ALL_S2_PM2.5_r3_NIGHT	Receptors exceeding 24-hr $PM_{2.5}$ SIL within the ACLF boundary (blue outline). Sources include Dynamis.
	PM_{10}	24-hr	ALL_S2_PM10_r3_7AP	Receptors exceeding 24-hr PM_{10} SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis and ACLF (ACLF sources operating 7am to 7pm only)
	PM_{10}	24-hr	ALL_S2_PM10_r3_NIGHT	Receptors exceeding 24-hr PM_{10} SIL within the ACLF boundary (blue outline). Sources include Dynamis.
	$PM_{2.5}$	Annual	ALL_S2_PM2.5ANN_r3_7AP	Receptors exceeding Annual $PM_{2.5}$ SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis and ACLF (ACLF sources operating 7am to 7pm only)
	$PM_{2.5}$	Annual	ALL_S2_PM2.5ANN_r3_Night	Receptors exceeding Annual $PM_{2.5}$ SIL within the ACLF boundary (blue outline). Sources include Dynamis.
	NO_x, SO_2	Annual	ALL_S2_NOSOAN_r3_7AP	Receptors exceeding Annual NO_x and SO_2 SIL within the 7am to 7pm public access area at the ACLF. Sources include Dynamis and ACLF (ACLF sources operating 7am to 7pm only).
	NO_x, SO_2	Annual	ALL_S2_NOSOAN_r3_NIGHT	Receptors exceeding Annual NO_x and SO_2 SIL within the ACLF boundary (blue outline). Sources include Dynamis.

The results of the full impact analysis for Scenario 1 and Scenario 2 are shown in Table 8 and Table 9, respectively.

Table 8 Full Impact Analysis Model Results - Scenario 1

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Concentration (ug/m^3)	NAAQS/ AAC/AACC (ug/m^3)	Modeled Value Used (5 years met data)
PM_{10}	24-hour	8.32	73	81.3	150	6th highest
$PM_{2.5}$	24-hr	8.62	19.3	27.9	35	Average 1st high for all meteorological years
	Annual	1.66	6.3	7.96	15	Average 1st high for all meteorological years
NO_2	1-hr	229.3	Background included in modeled impact	229.3	188	Max8th highest maximum daily 1-hr value for each year averaged for all years
	Annual	5.48	40	45.5	100	1st highest
SO_2	1-hr	64.7	33.1	97.8	196	Max 4th highest maximum daily 1-hr value for each year averaged for all years
	Annual	2.53	2.6	5.13	80	1st highest

Table 9 Full Impact Analysis Model Results - Scenario 2

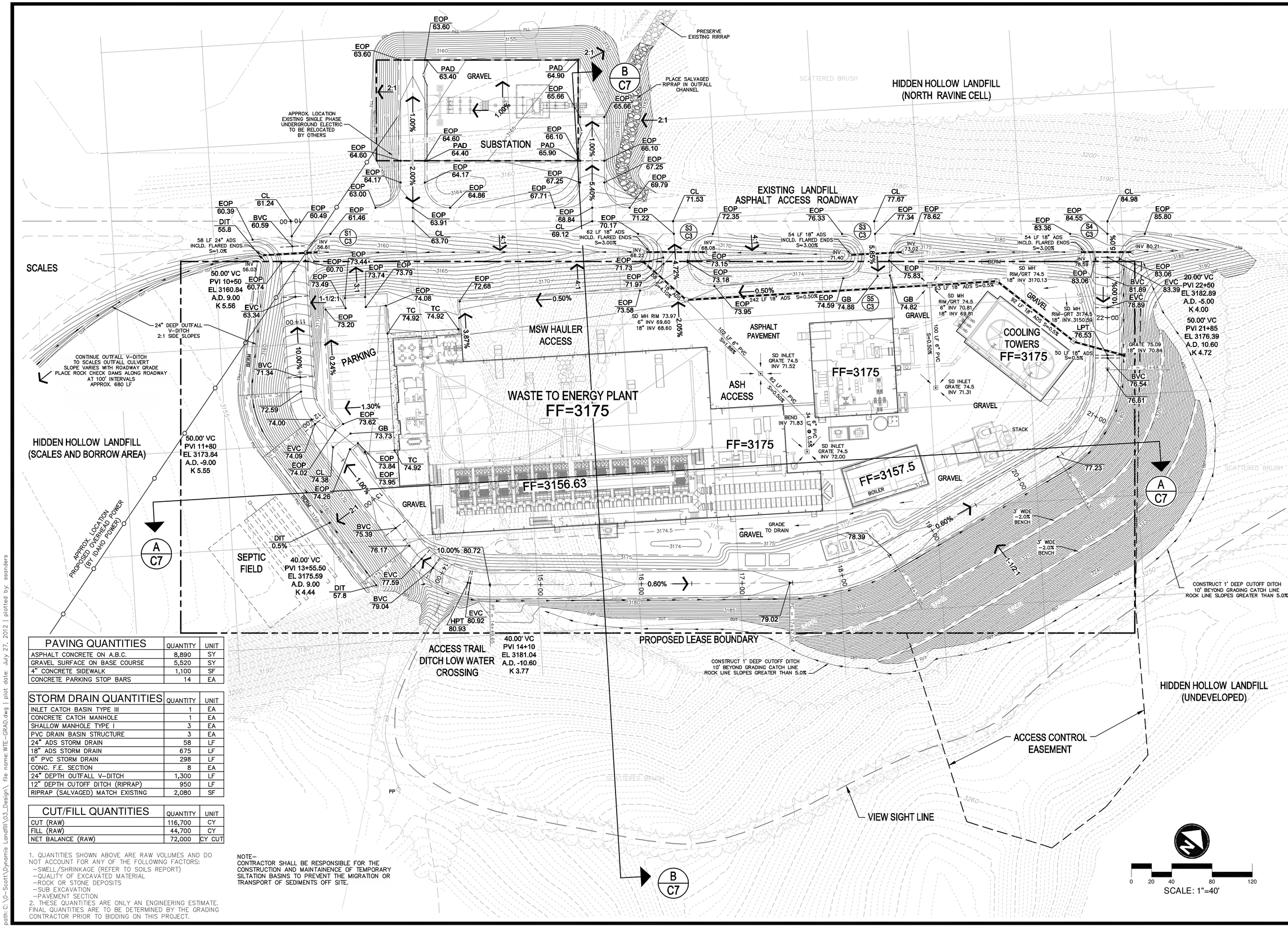
Pollutant	Averaging Period	Modeled Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Concentration (ug/m^3)	NAAQS/ AAC/AACC (ug/m^3)	Modeled Value Used (5 years met data)
PM_{10}	24-hour	8.32	73	81.3	150	6th highest
$PM_{2.5}$	24-hr	8.62	19.3	27.9	35	Average 1st high for all meteorological years
	Annual	1.65	6.3	7.95	15	Average 1st high for all meteorological years
NO_2	1-hr	229.3	Background included in modeled impact	229.3	188	Max8th highest maximum daily 1-hr value for each year averaged for all years
	Annual	5.46	40	45.5	100	1st highest
SO_2	1-hr	64.7	33.1	97.8	196	Max 4th highest maximum daily 1-hr value for each year averaged for all years
	Annual	2.52	2.6	5.12	80	1st highest

As shown in Table 8 and 9 above, maximum impacts of 1-hr NO_x exceed the NAAQs. These exceedances occur during the "7AM-7PM" model runs for Scenario 1 and Scenario 2. The MAXDAYCONT output option in AERMOD was used to determine if impacts from the Dynamis facility exceed the SIL at the receptors where exceedances of the 1-hr NOx NAAQS occur. A range of values from 8th high to 50th high was specified for the generated AERMOD MAXDAYCONT tables to adequately demonstrate the facility does not have a significant contribution to any modeled exceedance. For both Scenario 1 and Scenario 2 "7AM-7PM" model runs, the 1-hr NO_x standard was exceeded at at-least one receptor through the 46th high. The maximum contribution from Dynamis at each receptor where a NAAQS exceedance occurs is below the SIL. MAXDAYCONT output files are included in Appendix G. Dynamis sources are shown in the output files as PEAK, OFFPEAK and EMERGEN.

Electronic copies of all input, output, and support modeling files necessary to duplicate the model results accompany this submittal to IDEQ.

APPENDIX A

Site Location Map and Site Plans



PAVING QUANTITIES	QUANTITY	UNIT
ASPHALT CONCRETE ON A.B.C.	8,890	SY
GRAVEL SURFACE ON BASE COURSE	5,520	SY
4" CONCRETE SIDEWALK	1,100	SF
CONCRETE PARKING STOP BARS	14	EA

STORM DRAIN QUANTITIES	QUANTITY	UNIT
INLET CATCH BASIN TYPE III	1	EA
CONCRETE CATCH MANHOLE	1	EA
SHALLOW MANHOLE TYPE I	3	EA
PVC DRAIN BASIN STRUCTURE	3	EA
24" ADS STORM DRAIN	58	LF
18" ADS STORM DRAIN	675	LF
6" PVC STORM DRAIN	298	LF
CONC. F.E. SECTION	8	EA
24" DEPTH OUTFALL V-DITCH	1,300	LF
12" DEPTH CUTOFF DITCH (RIPRAP)	950	LF
RIPRAP (SALVAGED) MATCH EXISTING	2,080	SF

CUT/FILL QUANTITIES	QUANTITY	UNIT
CUT (RAW)	116,700	CY
FILL (RAW)	44,700	CY
NET BALANCE (RAW)	72,000	CY CUT

1. QUANTITIES SHOWN ABOVE ARE RAW VOLUMES AND DO NOT ACCOUNT FOR ANY OF THE FOLLOWING FACTORS:
   - SWELL/SHRINKAGE (REFER TO SOILS REPORT)
   - QUALITY OF EXCAVATED MATERIAL
   - ROCK OR STONE DEPOSITS
   - SUB EXCAVATION
   - PAVEMENT SECTION
2. THESE QUANTITIES ARE ONLY AN ENGINEERING ESTIMATE. FINAL QUANTITIES ARE TO BE DETERMINED BY THE GRADING CONTRACTOR PRIOR TO BIDDING ON THIS PROJECT.

NOTE–
CONTRACTOR SHALL BE RESPONSIBLE FOR THE CONSTRUCTION AND MAINTAINENCE OF TEMPORARY SILTATION BASINS TO PREVENT THE MIGRATION OR TRANSPORT OF SEDIMENTS OFF SITE.

PRELIMINARY NOT APPROVED FOR CONSTRUCTION

REVISIONS

DATE: JULY 27, 2012
DESIGNED BY: STAFF
DRAWN BY: STAFF
REVIEWED BY:
PROJECT:
ISSUE:

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DYNAMIS ENERGY, LLC

HIDDEN HOLLOW LANDFILL WASTE TO ENERGY PLANT
PLAN SHEET

GRADING PLAN

DYNAMIS ENERGY

C5

SHEET 5 OF 8

V. 10 R. 8

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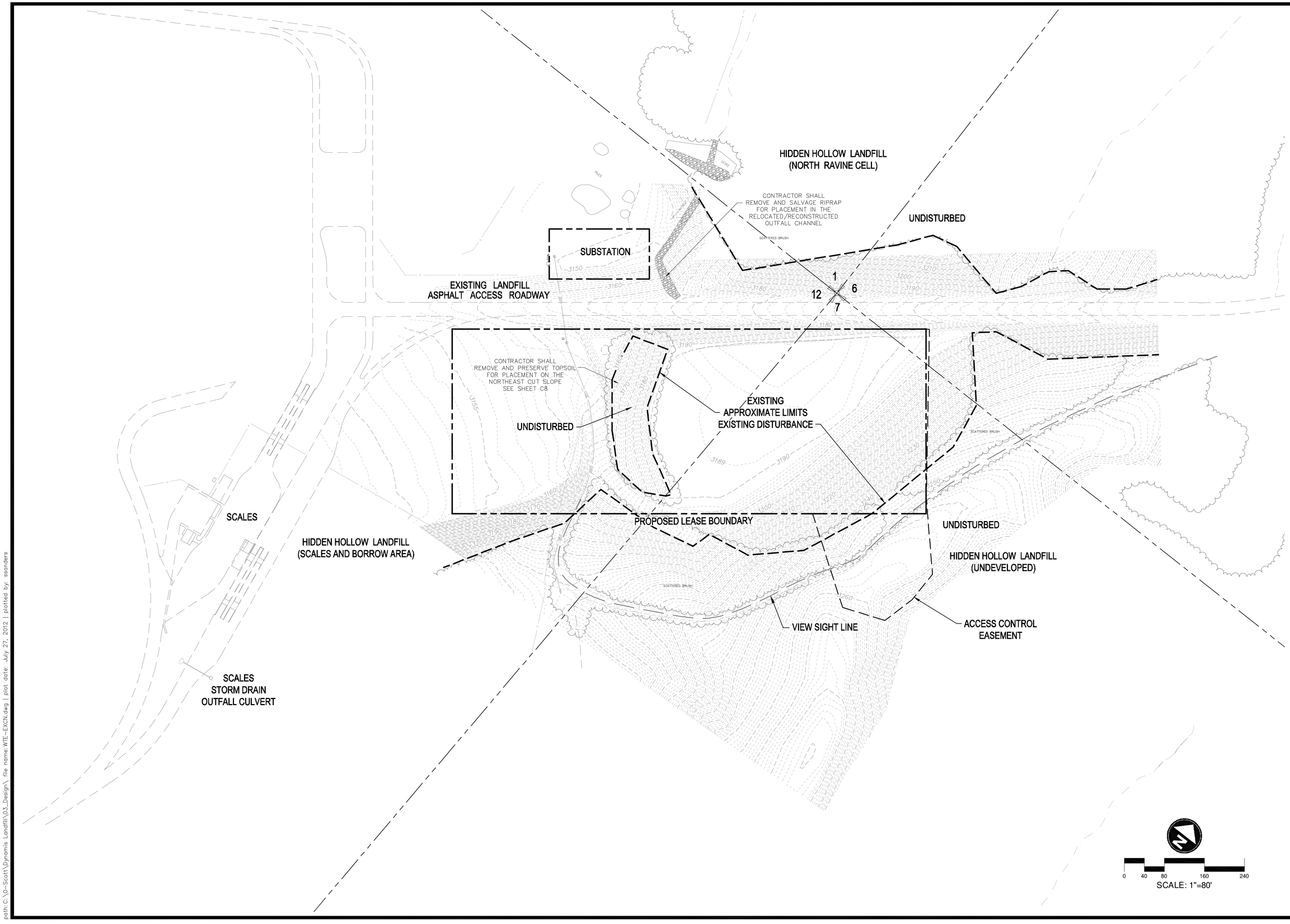

PRELIMINARY NOT APPROVED FOR CONSTRUCTION

REVISIONS

DATE: JULY 27, 2012
DESIGNED BY: STAFF
DRAWN BY: STAFF
REVIEWED BY:
PROJECT:
ISSUE: NOT TO EXCEED BUDGET

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DYNAMIS ENERGY, LLC

HIDDEN HOLLOW LANDFILL WASTE TO ENERGY PLANT
PLAN SHEET

EXISTING CONDITIONS PLAN

DYNAMIS ENERGY

C2

SHEET 2 OF 8

V. 10 R. 8

path: C:\0-Scott\Dynamis Landfill\03_Design\ file name: WTE-EXCN.dwg | plot date: July 27, 2012 | plotted by: ssanders

APPENDIX B

Scrubber, SNCR, Ash System Baghouse and Emergency Generator Specifications

1.0 INTRODUCTION

De-NOx Technologies, LLC (DNT) is pleased to offer Dynamis Energy, LLC the following revised Firm Price Proposal for the design and supply of a urea-based SNCR system. This system is to be installed on one 200,000pph MSW Gasification unit in Boise ID. The proposed system will utilize 50wt% urea solution.

DNT will provide the process design, mechanical design, electrical and control design, equipment selection, equipment fabrication, injector supply, and process guarantees.

The major design parameters are presented in Table 1.

TABLE 1
Design Conditions

Design Parameters	Typical
Combustor Steam Rate (pph)	200,000
Oxygen Level (% v)	4-6
Carbon Monoxide (lb/MMBTU)	<0.2
Load Range (%)	70-100
Furnace Exit Gas Temperature (degF)	1900-2000
Estimated MCR Reagent Consumption, GPH	5
Minimum Gas Residence Time after injection and before Boiler, sec	0.75
Design Uncontrolled NOX_x (pph, as NO2)	50
Guaranteed Controlled NOX_x (pph)	30

2.0 SCOPE OF SUPPLY

DNT will provide the following design services and equipment:

2.1 Equipment

- One (1) 6000 gallon non-metallic atmospheric pressure Storage Tank. The tank can be located outdoors on a properly designed level concrete foundation. It will be supplied with heating pads and temperature controls to maintain 80 degF at the local winter design temperature.

  The storage tank will be supplied with:

  - Side Bolted Manway
  - Corrosion barrier
  - UV resistant outer treatment
  - Hold Down and Lifting Lugs
  - Flanged fittings for Pump Suction, Vent, Fill, and Recirc
  - Isolation Valves
  - Level Indicator/Transmitter
  - Temperature Indicator/Transmitter

- One Control Module will be supplied to be located in a climate controlled enclosure (enclosure by others) in immediate proximity to the Storage Tank. This module will: 1)provide circulation and external heating of concentrated reagent, 2)filter and regulate the flow of reagent and dilution water, and 3)mix the reagent with dilution water for the boiler. The module will be pre-assembled.

  The proper amount of reagent is determined based upon feedback from a CEM system, and algorithms resident in the PLC System. Urea will be metered to the boiler unit through positive displacement pumps. Materials of construction for the concentrated reagent and diluted reagent lines shall be SS piping and/or tubing. Duplex strainers of 316 SS construction, capable of continuous filtering of the reagent and dilution water shall be provided. The device shall be capable of being maintained while on line.

  The Control Module will be supplied with a NEMA 4X enclosure which houses the Main Circuit Breaker/Handle, AB PLC components,,

motor starters, instrument/ power terminal strips, 24VDC Power Supply, and variable speed drives. The system will be capable of full manual operation from the face of the panel.

The Module will be supplied with reagent flow measurement, reagent circulation, external electric circulation heater, and automatic flush-out.

- Distribution Module. One Distribution Module will be provided in near proximity to the injection nozzles. The module distributes the supply of diluted reagent to each injector, as well as control atomizing air pressure. These modules are designed to save floor space and can be mounted on walls, columns, or over handrail.

- Dual Fluid Nozzle Atomizing Injectors. These injectors are DNT's proven and proprietary design. They have proven, excellent, service life on refuse and biomass units.

  The exact location of these ports will be determined during the contract phase of the project. This proposal assumes 6 injectors generally located 0.5 sec prior to the first convective tube surface. The injectors are inserted and retracted by hand. Flexible hoses, attached to the injectors with quick connects, will be supplied.

2.2 Engineering and Start-up Services. These services would include:

- P&ID's, Equipment Arrangement Drawings, equipment fabrication drawings, logic and interconnect drawings

- Specify, select, purchase, prefabricate, and deliver the equipment specified above.

- Five Maintenance and Operation Manuals.

2.3 Provided by Owner

- Approximately 3 GPM of dilution water @ 80 psig to the Control Module. This dilution water should be softened and generally be of drinking quality.

- Compressed Air – Approximately 90 scfm at a minimum pressure of 80 psig to the Distribution Panel.

- Fused disconnects for power to the tank panel, heat tracing and Control Module, as follows:
  - Control Module – 480 VAC, 20 Amp.
  - Tank – 120VAC, 4000 watt

- All local permits and/or licenses.

- Compliance and/or Performance Testing.

- Terminations to the Central Control Station, any additions to hardware/software and graphics/configuration.

- All Receiving and Installation, including all piping heat tracing.

3.0 PRICING

The firm price for the Scope as described herein is [redacted] freight excluded. The price includes 5 days of on-site Field Services for Mechanical Check-Out, Training and Start-Up. DNT's Terms and Conditions attached.

4.0 PROJECT SCHEDULE

Begin Equipment Design	At Notice to Proceed
Submit Mech and Elec Drawings for Approval	4 weeks after NTP
Shipment of Equipment	12 weeks after Approvals

APPENDIX C

Emissions Inventory (also included on CD)

Dynamis Energy, LLC
Ada County WTE Facility

FACILITY POTENTIAL TO EMIT - CRITERIA POLLUTANTS

	Criteria Pollutants											
	NOx Emissions		CO Emissions		PM-10/PM-2.5 Emissions		SOx Emissions		VOC Emissions		Lead Emissions	
Description	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Thermal Conversion Unit - Peak	17.96	52.43	10.90	31.83	3.66	10.68	8.54	24.94			0 03	0.09
Thermal Conversion Unit - OffPeak	2.65	3.86	1 61	0.54	0.54	0.79	1.26	1 84			0.00	0.01
Cooling Tower					0.02	0.08						
Ash System					0.45	1.97					5.10E-04	2.23E-03
Emergency Generator	1.30	0.33	0 26	0.07	0.03	0.01	0.98	0 25	1.19	0.30		
Ignition Systems	0.28	1.23	0 39	1.72	0.02	0.09	0.00	0 00	0.03	0.11	2.33E-06	1.02E-05
Total	**22.183**	**57.843**	**13.164**	**34.149**	**4.720**	**13.616**	**10.786**	**27.030**	**1.211**	**0.409**	**0.0358**	**0.099**

FACILITY POTENTIAL TO EMIT - TAPS

NON-CARCINOGENS (POUNDS PER HOUR)						
Pollutant	CAS #	TAP Emissions - Max (lb/hr)	TAP Emissions - Average (lb/hr)	TAP Emissions (tpy)	Screening Level (lb/hr)	Modeling? (Y/N)
Acrolein	107-02-8	1.13E-04	1.13E-04	2.82E-05	1.70E-02	No
Aluminum	7429-90-5	1.05E-01	1.02E-01	4.48E-01	6 67E-01	No
Antimony	7440-36-0	7.86E-04	5.63E-04	2.46E-03	3 30E-02	No
Barium	7440-39-3	7.92E-04	7.32E-04	3.21E-03	3 30E-02	No
Chromium	7440-47-3	1.85E-03	1.35E-03	5.92E-03	3 30E-02	No
Cobalt	7440-48-4	1.71E-03	1.62E-03	7.09E-03	3 30E-03	No
Copper	7440-50-8	1.12E-03	9.08E-04	3.98E-03	6.70E-02	No
Fluoride (as F) (Hydrogen Fl)	16984-48-8	2.84E-03	2.03E-03	8.91E-03	1 67E-01	No
Hexane	110-54-3	8.40E-03	8.40E-03	3.68E-02	1.20E+01	No
Hydrogen Chloride	7647-01-0	5.95E-01	5.95E-01	2 61E+00	5 00E-02	See Footnote 1
Manganese	7439-96-5	6.96E-03	5.23E-03	2.29E-02	3 33E-01	No
Mercury*	7439-97-6	3.10E-03	2.22E-03	9.72E-03	N/A	*
Molybdenum	7439-98-7	2.24E-03	1.61E-03	7.06E-03	3 33E-01	No
Naphthalene**	91-20-3	3.04E-06	3.04E-06	1 25E-05	9.10E-05	No
Pentane	109-66-0	1.21E-02	1.21E-02	5.31E-02	1.18E+02	No
Phosphorous	7723-14-0	2.66E-03	2.66E-03	1.17E-02	7 00E-03	No
Selenium	7782-49-2	2.22E-03	1.59E-03	6.95E-03	1 30E-02	No
Silver	7440-22-4	2.92E-07	2.92E-07	1.28E-06	7 00E-03	No
Toluene	108-88-3	5.15E-04	5.15E-04	1 94E-04	2.50E+01	No
o-Xylene	1330-20-7	3.48E-04	3.48E-04	8.70E-05	2.90E+01	No
Zinc	7440-66-6	3.42E-01	3.09E-01	1 35E+00	6 67E-01	No

*Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215.

**Although listed as a noncarcinogen in the Rules, DEQ has determined that naphthalene is a possible/probable carcinogen. Compliance for naphthalene emissions should be based on the EL or AACC listed in Section 586 for PAH.
1. Regulated under NSPS Subpart Eb, excluded from modeling under IDAPA 58 01.01 210.20.

CARCINOGENS (POUNDS PER HOUR)						
Pollutant	CAS #	TAP Emissions - Max (lb/hr)	TAP Emissions - Average (lb/hr)	TAP Emissions (tpy)	Screening Level (lb/hr)	Modeling? (Y/N)
Acetaldehyde	75-07-0	9.37E-04	9.37E-04	5.35E-05	3 00E-03	No
Arsenic	7440-38-2	7.46E-07	7.46E-07	3.27E-06	1 50E-06	No
Benzene	71-43-2	1.15E-03	1.15E-03	3 28E-04	8.00E-04	Yes
Beryllium	7440-41-7	4.48E-08	4.48E-08	1.96E-07	2.80E-05	No
Cadmium	7440-43-9	3.48E-03	2.50E-03	1.09E-02	3.70E-06	See Footnote 1
Dioxin/Furan	1746-01-6	4.49E-09	3.21E-09	1.41E-08	1.50E-10	See Footnote 1
Formaldehyde	50-00-0	1.79E-03	1.79E-03	1 89E-03	5.10E-04	Yes
Nickel	7440-02-0	1.51E-02	8.69E-03	3 81E-02	2.70E-05	Yes
Benzo(a)pyrene	50-32-8	5.60E-09	5.60E-09	2.45E-08	2.00E-06	No
Benz(a)anthracene	56-55-3	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Benzo(b)fluoranthene	205-82-3	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Benzo(k)fluoranthene	205-99-2	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Chrysene	218-01-9	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Dibenzo(a,h)anthracene	53-70-3	5.60E-09	5.60E-09	2.45E-08	2.00E-06	No
Indeno(1,2,3-cd)pyrene	193-39-5	8.40E-09	8.40E-09	3 68E-08	2.00E-06	No
Total PAHs		2.45E-07	2.45E-07	1 07E-06	9.10E-05	No

Dynamis Energy WTE Facility
Thermal Conversion System
Thermal Conversion Unit

Total MSW Throughput	367.2	tpd
Total MSW Throughput	15.30	ton/hr
Total MSW Throughput	30600	lb/hr
Peak Operating Hours	5840	hr/yr
Off-Peak Operating Hours	2920	hr/yr
Peak Exhaust Flow	150,865	acfm @ 125.4F
Off-Peak Exhaust Flow	39,100	acfm @ 134.5F

Hours	7am - 11pm	11pm-7am
Throughput (tpd)	342	25.2
Throughput (tph)	21.375	3.15
Percent of day	0.67	0.33

Pollutant Emission Factors	PM/PM10/ PM2.5 lb/ton	SO2 lb/ton	NOx lb/ton	CO lb/ton	Lead lb/ton
Thermal Conversion Unit Exhaust	0.29	1.39	1.4	0.51	1.44E-03

PM, NOx, CO, SO2, Lead Emission factor from source test averages
*SO2 Emission rate based on scrubber manufacturer guarantee of 71.25% control. PM2.5 emission rate based on scrubber manufacturere guarantee of 41%.
*NOx Emission rate based on SNCR manufacturer guarantee of 40% control.

7am-11pm - PEAK

	PM/PM10/PM2.5		SO_2		NOx		CO		Lead	
Pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Thermal Conversion Unit Exhaust Uncontrolled	6.20	18.10	29.71	86.76	29.93	87.38	10.90	31.83	0.03	0.09
Thermal Conversion Unit Exhaust Controlled	3.66	10.68	8.54	24.94	17.96	52.43	10.90	31.83	0.03	0.09
Controlled Boiler Stack Emissions (Thermal Unit + Ignition System)	3.68	10.74	8.54	24.94	18.23	53.25	11.29	32.98	0.03	0.09

11pm-7am - OFF PEAK

	PM/PM10/PM2.5		SO_2		NOx		CO		Lead	
Pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Thermal Conversion Unit Exhaust Uncontrolled	0.91	1.33	4.38	6.39	4.41	6.44	1.61	0.54	0.00	0.01
Thermal Conversion Unit Exhaust Controlled	0.54	0.79	1.26	1.84	2.65	3.86	1.61	0.54	0.00	0.01
Controlled Boiler Stack Emissions (Thermal Unit + Ignition System)	0.56	0.82	1.26	1.84	2.93	4.27	2.00	1.11	0.005	0.01

TOXIC AIR POLLUTANTS (TAPs) CALCULATIONS

NON CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	TAP Emission Factor (lb/ton)	Peak TAP Emissions (lb/hr)	Off Peak TAP Emissions (lb/hr)	Average TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling (based on peak)? (Y/N)	Modeling (based on Average)? (Y/N)
Aluminium	7429-90-5	4.74E-04	8.11E-03	1.19E-03	5.80E-03	6.67E-01	No	No
Antimony	7440-36-0	4.60E-05	7.86E-04	1.16E-04	5.63E-04	3.30E-02	No	No
Barium	7440-39-3	1.23E-05	2.11E-04	3.10E-05	1.51E-04	3.30E-02	No	No
Chromium	7440-47-3	1.03E-04	1.76E-03	2.60E-04	1.26E-03	3.30E-02	No	No
Copper	7440-50-8	4.33E-05	7.41E-04	1.09E-04	5.30E-04	6.70E-02	No	No
Cobalt	7440-48-4	1.77E-05	3.03E-04	4.47E-05	2.17E-04	3.30E-03	No	No
Hydrogen Chloride	7647-01-0	See Note 1 Below	5.95E-01	5.95E-01	5.95E-01	5.00E-02	Mode ing not required (IDAPA 58.01.01 210.20)	
Hydrogen Flouride	NA	1.33E-04	2.84E-03	4.19E-04	2.03E-03	1.67E-01	No	No
Manganese	7439-96-5	3.56E-04	6.08E-03	8.96E-04	4.35E-03	3.33E-01	No	No
Mercury	7439-97-6	1.45E-04	3.10E-03	4.57E-04	2.22E-03	N/A	See Note 2 Below	
Molybdenum	7439-98-7	1.30E-04	2.22E-03	3.27E-04	1.59E-03	3.33E-01	No	No
Selenium	7782-49-2	1.30E-04	2.22E-03	3.27E-04	1.59E-03	1.30E-02	No	No
Zinc	7440-66-6	6.68E-03	1.14E-01	1.68E-02	8.18E-02	6.67E-01	No	No

TAPs Emission factor from source test averages.
1. HCl emission rate of 0.595 lb/hr based on baghouse manufacturer guarantee

2. Mercury is not listed under IDAPA 58.01.01 Section 585 as a TAP. However, it is listed here to show compliance with the MBACT rule under Section 215
The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (w th the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

CARCINOGENS (POUNDS PER HOUR)

Pollutant	CAS #	TAP Emission Factor (lb/ton)	Peak TAP Emissions (lb/hr)	Off Peak TAP Emissions (lb/hr)	Average TAP Emissions (lb/hr)	Screening Level (lb/hr)	Modeling (based on peak)? (Y/N)	Modeling (based on Average)? (Y/N)	Stack Emissions (Thermal Unit + Ignition System) PEAK lb/hr	PEAK tpy	OFF PEAK lb/hr	OFF PEAK tpy
Cadmium	7440-43-9	2.02E-04	3.46E-03	5.10E-04	2.48E-03	3.7E-06	Mode ing not required (IDAPA 58.01.01 210.20)					
Dioxin/Furan		2.10E-10	4.49E-09	6.62E-10	3.21E-09	1.50E-10	Mode ing not required (IDAPA 58.01.01 210.20)					
Nickel	7440-02-0	8.81E-04	1.51E-02	2.22E-03	8.63E-03	2.70E-05	Yes	Yes	1.51E-02	4.40E-02	2.23E-03	3.25E-03

TAPs Emission factor from source test averages.
The scrubber manufacturer guarantees 41% control of PM2.5 and smaller, with higher control efficiency expected for larger particulates. Metals emissions (w th the exception of Mercury) from the thermal unit (including primary ignition system) will be in particulate form. Metals emissions estimates include a conservative 20% control of particulate metals.

Dynamis Energy WTE Facility
Thermal Conversion System - Hidden Hollow Landfill
Thermal Conversion Units - Ignition Systems Criteria Pollutants

Primary gasification ignition systems will operate on natural gas. Primary chamber ignition will be evenly distributed hroughout the day; independent of MSW throughput and peak/off-peak operation.

CRITERIA POLLUTANT COMBUSTION CALCULATIONS
NATURAL GAS

Emission Unit	Fuel Usage		Conversions	
Primary Chamber Ignition (total)	111,953 scf/day		40862845	1020 MMBtu/10^6 scf
Primary Chamber Ignition (total)	4.76 MMBtu/hr			

Emission Factors

NOx	100 lb/10^6 scf	AP-42, Table 1.4-1, 1998
CO	84 lb/10^6 scf	AP-42, Table 1.4-1, 1998
PM-10	7.6 lb/10^6 scf	AP-42, Table 1.4-2, 1998
SOx	0.6 lb/10^6 scf	AP-42, Table 1.4-2, 1998
VOC	5.5 lb/10^6 scf	AP-42, Table 1.4-2, 1998
Lead	0.0005 lb/10^6 scf	AP-42, Table 1.4-2, 1998

Description	Capacity (MMBtu/hr)	Throughput (scf/hr)	Pounds per Hour					
			NOx Emissions (lb/hr)	CO Emissions (lb/hr)	PM-10/PM-2.5 Emissions (lb/hr)	SOx Emissions (lb/hr)	VOC Emissions (lb/hr)	Lead Emissions (lb/hr)
Primary Chamber Ignitions - Uncontrolled	4.76	4,665	0.4665	0.3918	0.0355	0.0028	0.0257	0.0000023
Primary Chamber Ignitions - Controlled	4.76	4,665	0.2799	0.3918	0.0209	0.0008	0.0257	0.0000023

*SO2 Emission rate based on scrubber manufacturer guarantee of 71.25% control. PM2.5 emission rate based on scrubber manufacturere guarantee of 41%.

*NOx Emission rate based on SNCR manufacturer guarantee of 40% control.

Description	Capacity (MMBtu/hr)	Throughput (scf/yr)	Ton per Year					
			Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)	Emissions (T/yr)
Primary Chamber Ignitions - Uncontrolled	4.76	4,665	2.04	1.72	0.16	0.01	0.11	1.02E-05
Primary Chamber Ignitions - Controlled (Peak)	4.76	4,665	0.82	1.14	0.06	0.00	0.07	0.00
Primary Chamber Ignitions - Controlled (Off-Peak)	4.76	4,665	0.41	0.57	0.03	0.00	0.04	0.00

APPENDIX D

DEQ Modeling Forms

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION

Revision 3
4/5/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Dynamis Energy, LLC
Facility Name:	Hidden Hollow Waste-To-Energy (WTE) Facility
Facility ID No.:	
Brief Project Description:	Municipal solid waste thermal conversion facility located at the Ada County Landfill

SUMMARY OF AIR IMPACT ANALYSIS RESULTS - CRITERIA POLLUTANTS

				2.	3.	4.		5.
Criteria Pollutants	**Averaging Period**	**Significant Impact Analysis Results (µg/m3)**	**Significant Contribution Level (µg/m3)**	**Full Impact Analysis Results (µg/m3)**	**Background Concentration (µg/m3)**	**Total Ambient Impact (µg/m3)**	**NAAQS (µg/m3)**	**Percent of NAAQS**
$PM_{2.5}$	24-hour	8.62	1.2	8.62	19.30	27.92	35	80%
	Annual	1.63	0.3	1.66	6.30	7.96	15	53%
PM_{10}	24-hr	10.82	5	8.32	73.00	81.32	150	54%
SO_2	1-hr	93.66	7.9	64.68	33.10	97.78	196	50%
	Annual	2.49	1	2.53	2.60	5.13	80	6%
NO_2	1-hr	141.90	7.5	229.34	Variable	229.34	188	122%
	Annual	9.05	1	5.48	40.00	45.48	100	45%
CO	1-hr	n/a	2000	n/a	n/a	n/a	10000	n/a
	8-hr	n/a	500	n/a	n/a	n/a	40000	n/a

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline - 1-877-5PERMIT

PERMIT TO CONSTRUCT APPLICATION
Revision 3
3/27/2007

Please see instructions on page 2 before filling out the form.

Company Name:	Dynamis Energy, LLC
Facility Name:	Hidden Hollow Waste-To-Energy (WTE) Facility
Facility ID No.:	
Brief Project Description:	Municipal solid waste thermal conversion facility located at the Ada County Landfill

POINT SOURCE STACK PARAMETERS

1.	2.	3a.	3b.	4.	5.	6.	7.	8.	9.	10.
Emissions units	**Stack ID**	**UTM Easting (m)**	**UTM Northing (m)**	**Base Elevation (m)**	**Stack Height (m)**	**Modeled Diameter (m)**	**Stack Exit Temperature (K)**	**Stack Exit Flowrate (acfm)**	**Stack Exit Velocity (m/s)**	**Stack orientation (e.g., horizontal, rain cap)**
Point Source(s)										
UNITPEAK		558,564 86	4,839,455.69	967.74	18.29	1.52	325.00	150,865.00	39.03	Vertical
UNIT1OP		558,564 86	4,839,455.69	967.74	18.29	1.52	330.00	39,100.00	10.12	Vertical
ASHBH		558,516 34	4,839,409.81	967.74	16.76	0.46	310.93	14,000.00	40.25	Vertical
EMERGEN		558,527 07	4,839,379.75	967.74	3.05	0.13	772.65	2,461.43	91.69	Vertical
CT1		558,541 27	4,839,482.28	967.74	10.44	10.00	303.52	1,181,020.80	7.10	Vertical
CT2		558,554.77	4,839,482.28	967.74	10.44	10.00	303.52	1,181,020.80	7.10	Vertical
HGEN1		557,482 93	4,838,615.04	872.63	4.39	0.37	754.26	12,484.05	56.00	Vertical
HGEN2		557,479.78	4,838,607.43	872.40	4.39	0.37	754.26	12,484.05	56.00	Vertical
HGEN3		557,475 20	4,838,597.18	871.97	4.39	0.37	754.26	12,484.05	56.00	Vertical
HGEN4		557,472 06	4,838,589.83	871.69	4.39	0.37	754.26	12,484.05	56.00	Vertical
FLARE1 - Scenario 1		557,489 99	4,838,641.83	873.88	12.19	3.05	1,064.00	4,947.39	0.32	Vertical
FLARE1 - Scenario 2		557,489 99	4,838,641.83	873.88	12.19	3.05	1,064.00	8,750.70	0.57	Vertical
FLARE2		557,494.64	4,838,635.18	872.90	12.19	3.05	1,060.00	8,719.77	0.56	Vertical
CCHIPGEN		558,120 57	4,839,320.81	984.00	1.83	0.20	768.71	3,439.12	50.00	Vertical
CSCRNGEN		558,143.64	4,839,310.00	986.00	1.83	0.08	797.00	483.14	50.00	Vertical

APPENDIX E

SIL Receptor List (on CD)

APPENDIX F

Model Protocol Approval

APPENDIX G

MAXDAYCONT Output Files (on CD)

Revised Electronic Modeling Files Received via Hand-Delivery

Revision 4

July 30, 2012

(files not included)

From: Shannon Manoulian <smanoulian@jbrenv.com>
Sent: Tuesday, July 31, 2012 5:55 PM
To: Darrin Pampaian
Subject: Re: CEMS

Darrin,

Dynamis only committed to the CEMS for the pollutants it is required for. We are still leaning toward stack test for the others. At NO point did we commit to CEMS for dioxin, mercury, etc..

Will call you tomorrow.

Thanks,
Shannon

Sent from my HTC on the Now Network from Sprint!

----- Reply message -----
From: "Darrin.Pampaian@deq.idaho.gov" <Darrin.Pampaian@deq.idaho.gov>
Date: Tue, Jul 31, 2012 4:05 PM
Subject: CEMS
To: "Shannon Manoulian" <smanoulian@jbrenv.com>

Shannon,

Mike said he saw online that Dynamis had committed to a CEMS at one of the meetings. If this is true it might be better for Dynamis to commit to this in writing and I could just have the permit set to the CEMS option in Subpart Eb.

Darrin Pampaian, P.E.
Staff Engineer
Idaho DEQ - Air Quality Division
1410 N. Hilton, Boise ID 83706-1255
ph: (208) 373-0587 fax: (208) 373-0340
Darrin.Pampaian@deq.idaho.gov

From: Shannon Manoulian <smanoulian@jbrenv.com>
Sent: Tuesday, August 07, 2012 12:43 PM
To: Darrin Pampaian
Subject: RE: Ammonia Slip
Attachments: 062-preformance revC.pdf

Hi Darrin,

Here is the scrubber manufacturer guarantee for ammonia slip control. The scrubber manufacturer guarantees 82% control of ammonia slip for incoming ammonia streams of up to 3.23 lb/hr, which is the maximum estimated slip for both peak and off-peak flow conditions. This gives 0.58 lb/hr emissions. The EL from IDAPA 585 is 1.2 lb/hr, so we are below the modeling threshold. Do you need an 'official' calculation in a spreadsheet, or does what is written in this email work?

Also included in the guarantee is the pH range for the scrubber liquor.

In addition, the pressure drop across the Coalescing Mesh Pad is approximately 5.6-inches of water column during normal operation. If the pressure drop across the coalescing mesh pad increases to a point between 6.6-and 7.6 inches of water column, then mesh pad washing will be initiated.

Let me know if you have any questions.

Thanks!
Shannon

From: Darrin.Pampaian@deq.idaho.gov [mailto:Darrin.Pampaian@deq.idaho.gov]
Sent: Monday, August 06, 2012 3:40 PM
To: Shannon Manoulian
Subject: Ammonia Slip

Shannon,

If there is ammonia slip the emissions should be compared to the EL in 585 but I don't see this. Did you do this in the application?

Darrin Pampaian, P.E.
Staff Engineer
Idaho DEQ - Air Quality Division
1410 N. Hilton, Boise ID 83706-1255
ph: (208) 373-0587 fax: (208) 373-0340
Darrin.Pampaian@deq.idaho.gov

Scrubber Ammonia Control Guarantee

DIRECT CONTACT LLC

Main: 2555 – 34th Street NE – Canton, OH – 44705 (330) 437-0444
West Coast: P.O. Box 2969 - Renton, WA - 98056 (425) 235-1723

August 14, 2012

Dynamis Energy, LLC
776 East Riverside Drive
Suite 150
Eagle, Idaho 833616

Attention: Chris Durand, Project Manager

Reference: MSW to Energy - ADA, County

Subject: Heat Recovery and Pollutant Abatement System
DCI-HTR Scrubbing Heat Recovery System
Revision D

Dear Chris,

We have completed the design of our subject system, and have determined the expect abatement results. These results are based on "Peak Load" Production:

Peak Load Production:

Incoming Flue Gas Mass Flow:	
Non-Reactive/Non-Condensable	491,670-lb/hr
Water Vapor	50,610-lb/hr
Sulfur Dioxide Gas	40-lb/hr
Hydrochloric Acid Vapor	10-lb/hr
Ammonia Vapor	3.57-lb/hr
PM_{10}	7-lb/hr
$PM_{2.5}$ & smaller	6.5-lb/hr
Fahrenheit Temperature	350°F
Absolute Pressure	12.88-Psia

Given the above conditions, design liquid irrigation rates and contact solution pH ranging between 9.5 and 11, and 31-million BTU/hr rate of heat recovery, Direct Contact LLC expects to reduce the exiting gas at the following rates:

Component	*Incoming*	*Removal*
Sulfur Dioxide Gas	40-lb/hr	71.25%
Hydrochloric Acid Vapor	10-lb/hr	94.05%
Ammonia Vapor	3.57-lb/hr	82.00%
PM_{10}	7-lb/hr	99.00%
$PM_{2.5}$ & smaller	6.5-lb/hr	41.00%

Direct Contact LLC will conditionally guarantee the above removal rates at Peak Load Production or lower rate.

Expected removal rates will change based on and relative to the incoming conditions:

If heat recovery rate decreases at a constant mass flow rate, then the expected particulate recovery efficiency will improve slightly, but the acid gases removal efficiency will decrease slightly.

If flue gas mass flow rate is reduced, then the acid gases capture efficiency will increase slightly, but the particulate capture efficiency will decrease slightly.

If the solution in contact with the flue gas has its pH raised then the acid gas capture efficiency will increase conversely if the pH drops the acid gas capture rate will decrease.

As the moisture content of gas entering the DCLLC 'Hydro Thermal Recovery' vessel increases, the PM2.5 particulate removal will increase.

Per our ongoing discussion, I trust that this will clearly state what removal rates we can expect to provide for your 'Peak Load Conditions.' Please contact me with any questions you have on these numbers or any of the above.

Direct Contact LLC appreciates the opportunity to assist Dynamis Energy on your Heat Recovery and Pollution Abatement System.

Thank you for your continued consideration.

With *Warmest* Regards,

Bill Carson, PE

CHIEF ENGINEER

Direct Contact LLC

Waste Heat Recovery... adding up to much more than a drop in the bucket!

(425) 235-1723 **x101** // **cell** (206) 295-7678// fax (425) 277-5780

Energy-Efficiency-Environment

Cooling Tower TDS Information

JBR Environmental Consultants, Inc.
7669 W. Riverside Dr., Ste. 101
Boise, Idaho 83714
[p] 208.853.0883
[f] 208.853.0884
www.jbrenv.com

MEMORANDUM

To: Darrin Pampaian, IDEQ
Darrin Mehr, IDEQ

From: Shannon Manoulian, JBR

Date: August 15, 2012

Subject: Dynamis Ada County WTE Facility
Increase Cooling Tower Emission Rate

As part of the permit drafting process, DEQ requested verification of the Total Dissolved Solids (TDS) value used to determine $PM_{2.5}/PM_{10}$ emissions from the cooling towers. While preparing the information for submittal to DEQ, Dynamis determined that the value of 94 ppm TDS used in the $PM_{2.5}/PM_{10}$ calculation was from an analysis preformed on a well located near the project site.

However, the cooling tower intake water will be provided by United Water through the public water supply; the cooling tower will not use the onsite well. Analytical results from samples taken of the public water supply in March 2012 and June 2012 show TDS concentrations of 180 ppm and 210 ppm, respectively. The analytical results are included with this memo. Based on this discovery, Dynamis is submitting revised $PM_{2.5}/PM_{10}$ emissions calculations for the cooling towers. Total $PM_{2.5}/PM_{10}$ revised emissions from the cooling towers are 0.036 lb/hr (0.018 lb/hr/tower) and 0.16 tpy (0.08 tpy/tower).

The revised emissions were input into the air dispersion model SIL analysis to determine any increased impacts due to the increased cooling tower emissions. Facility-wide 1st high 24-hr $PM_{2.5}$ emissions increased from 8.62 ug/m3 to 8.69 ug/m3; 1st high 24-hr PM_{10} emissions increased from 10.8 ug/m3 to 10.87 ug/m3; annual $PM_{2.5}$ emissions increased from 1.63 ug/m3 to 1.64 ug/m3.

Dynamis reviewed the receptors exceeding the SIL for the increased $PM_{2.5}/PM_{10}$ impacts. The increase in $PM_{2.5}$ and PM_{10} emissions and subsequent increase in ambient impacts from the cooling towers results in one additional receptor exceeding the 24-hr $PM_{2.5}$ SIL and one additional receptor exceeding the 24-hr PM_{10} SIL. Based on the location and ambient concentration of these additional receptors, it is not anticipated that any exceedance of the 24-hr $PM_{2.5}$ or 24-hr PM_{10} NAAQS would occur in the full impact modeling analysis. There were no additional receptors that exceeded the annual $PM_{2.5}$ SIL.

Analytical Laboratories, Inc.

1804 N. 33rd Street
Boise, Idaho 83703
Phone (208) 342-5515

Date Report Printed: 4/12/2012 11:16:3

http://www.analyticallaboratories.com

Laboratory Analysis Report

Sample Number: 1208561

Attn:
DYNAMIS GROUP, LLC
776 E RIVERSIDE DR STE 150
EAGLE, ID 83616

Collected By:

Submitted By: D PERGANDE

Source of Sample:
WATER SAMPLE

Time of Collection: 15:10
Date of Collection: 3/27/2012
Date Received: 3/27/2012
Report Date: 4/11/2012

PWS#:

Field Temp: Temp Rcvd in Lab:

PWS Name:

Test Requested	MCL	Analysis Result	Units	MDL	Method	Date Completed	Analyst
Calcium Hardness	UR	78.3	mg/L	1.25	EPA 200.7	4/3/2012	KC
Alkalinity	UR	115	mg/L CaCO3		SM 2320B	4/6/2012	SS
pH	UR	7.1	S.U.		SM 4500-H B	3/27/2012	JMS
Turbidity		<0.5	NTU	0.5	EPA 180.1	3/27/2012	SS
Total Dissolved Solids	UR	180	mg/L	25	SM 2540C	3/29/2012	MG
Total Suspended Solids		<3	mg/L	3	SM 2540 D	3/28/2012	DLR

CC: DOYLE@DYNAMISENERGY.COM

MCL = Maximum Contamination Level
MDL = Method/Minimum Detection Limit
UR = Unregulated

Thank you for choosing Analytical Laboratories for your testing needs.

If you have any questions about this report, or any future analytical needs, please contact your client manager:

Brian M. McGovern

Laboratory Analysis Report

Date: 6/19/2012
Company Name: Dynamis Energy Boise,ID
Sample: RR @ Ada County Landfill Scale

Sample Date: 6/4/2012
Laboratory Number: 121435

Water Analysis

ANALYSIS	RESULT	UNITS
pH	7.24	units
Conductivity	300	umhos/cm
Total Organic Carbon	1.2	mg/L
P-Alkalinity (CaCO3)	0	mg/L
M-Alkalinity (CaCO3)	140	mg/L
Bromide	<0.5	mg/L
Chloride	10.8	mg/L
Fluoride	<0.4	mg/L
Nitrate (NO3)	9.48	mg/L
Nitrite (NO2)	<0.5	mg/L
Sulfur (SO4)	17.0	mg/L
Total Phosphate	0.50	mg/L
Ortho-Phosphate	0.43	mg/L
TDS	210	mg/L
TSS	<1.0	mg/L
Nitrogen, Ammonia	<0.05	mg/L

SNCR Ammonia Slip Information

From: "David Wojichowski" <dwojichowski@de-nox.com>
Date: August 1, 2012 6:31:57 AM MDT
To: "'Chris Durand'" <cdurand@dynamisenergy.com>
Cc: "'Solvason, John'" <JSolvason@eeeug.com>
Subject: RE: Dynamis SNCR

As you might expect, estimation of ammonia slip on paper is difficult to impossible. It greatly depends upon combustion conditions, reagent stoiciometry, and mixing effectiveness.

Your application should be better than a typical waterwall boiler application. In those, we typically see 10 ppmv or less during optimized operation.

David L. Wojichowski, P.E.
President
De-NOx Technologies, LLC
(603) 974-1411
(815) 301-8450 E-Fax
www.de-nox.com

This email message and any attachments are intended only for the use of the addressee named above and may contain information that is privileged and confidential. If you are not the intended recipient, any dissemination, distribution, or copying is strictly prohibited. If you received this email message in error, please immediately notify the sender by replying to this email message or by telephone and delete the message from your email system. Thank you.

-----Original Message-----
From: Chris Durand [mailto:cdurand@dynamisenergy.com]
Sent: Tuesday, July 31, 2012 6:13 PM
To: dwojichowski@de-nox.com
Subject: Dynamis SNCR

David,

Justin and John from Evergreen said I could contact you directly with questions.

Do you have an estimate on the maximum amount of ammonia slip that your system will typically operate below? We need this information for the

scrubber company to estimate the removal guarantee for permitting.

Thank you,

Chris durand

Sent from my Dynamis Energy iPhone

No virus found in this message.
Checked by AVG - www.avg.com
Version: 2012.0.2196 / Virus Database: 2437/5167 - Release Date: 07/31/12

Additional Scrubber Operating Parameters

(includes Excel file)

From: Bill Carson
To: Chris Durand
Cc: Shannon Manoulian; Curt Rothman
Subject: RE: Question to DEQ
Date: Tuesday, August 14, 2012 4:36:13 PM

Chris,

There is 230-gpm to the non-cooled bank of sprays on the lower bed of structured packing and 200-gpm of the cooled bank of sprays on the upper bed of structural packing. The is the same for each heat recovery pollution abatement vessel.

The water continuously sprayed on the mist eliminator pads drains into the packing.

With Warmest Regards,

Bill Carson

CHIEF ENGINEER
Direct Contact LLC
Waste Heat Recovery... adding up to much more than a drop in the bucket!
(425) 235-1723 **x101 // cell** (206) 295-7678// fax (425) 277-5780
Energy-Efficiency-Environment

From: Chris Durand [mailto:cdurand@dynamisenergy.com]
Sent: Tuesday, August 14, 2012 3:00 PM
To: Bill Carson
Cc: Shannon K. Manoulian (smanoulian@jbrenv.com); Curt Rothman
Subject: Re: Question to DEQ

Thanks Bill,

One more point I want to be sure on. There are additional sprays on the structured packing sections correct? What is the water flow rate through the structured packing sections? I have several numbers from a few different versions of the diagrams so I can't get them to agree.

Regards,

Christopher Durand PE
Dynamis Energy, LLC
776 E Riverside Drive, Ste. 150
Eagle, ID 83616
208-938-2680 x 1016 (o)
208-869-0515 (c)
208-938-268 (f)
cdurand@dynamisenergy.com

On Aug 14, 2012, at 3:06 PM, Bill Carson wrote:

Curt,

The coalescing section will be the see the majority of the pressure drop and flow fluctuation correct? Yes the majority of differential pressure across the heat recovery vessel results from the coalescing scrubber. The pressure drop across the coalescing scrubber will increase with increase flow. As solids buildup in the mesh pads, pressure drop will increase, for any given flow.

With that said can we assume the other sections will have relatively constant drops and water flow rates? The rest of the system's pressure drop variation of gas flow. Solid particulate buildup should never occur in the packing with the relatively large opening and high irrigation rates.

That would put the pressure drop range from 7.7 to 9.2 through the coalescing and mist eliminator sections with an additional rather constant (aside from the rare spray down of the indirect section) drop across the sections up stream. Do you have an estimate on the drop upstream of the coalescing sections? We plan on have a fan that can handle a 22-inches of water column (WC) static pressure at design flow. The pressure is 6-inces of WC of vacuum at inlet of DCLLC's equipment. 2.5-inch WC across the coils, 4-inch WC across the packed section and 9.2 inch WC across the coalescing scrubber.

Likewise with the flow rates through the structured packing sections. I also noticed in your documents that the water ph ranged from 9.5 to 11 with a set point of 10.5. Is this correct? Yes.

With Warmest Regards,

Bill Carson

CHIEF ENGINEER
Direct Contact LLC
Waste Heat Recovery... adding up to much more than a drop in the bucket!
(425) 235-1723 **x101 // cell** (206) 295-7678// fax (425) 277-5780
Energy-Efficiency-Environment

From: Chris Durand [mailto:cdurand@dynamisenergy.com]
Sent: Tuesday, August 14, 2012 12:39 PM
To: Bill Carson
Cc: Shannon K. Manoulian (smanoulian@jbrenv.com); Curt Rothman
Subject: Re: Question to DEQ

Bill,

The coalescing section will be the see the majority of the pressure drop and flow fluctuation correct? With that said can we assume the other sections will have relatively constant drops and water flow rates? That would put the pressure drop range from 7.7 to 9.2 through the coalescing and mist eliminator sections with an additional rather constant (aside from the rare spray down of the indirect section) drop across the sections up stream. Do you have an estimate on the drop upstream of the coalescing sections? Likewise with the flow rates through the structured packing sections. I also noticed in your documents that the water ph ranged from 9.5 to 11 with a set point of 10.5. Is this correct?

Thanks,

Sent from my Dynamis Energy iPhone

On Aug 14, 2012, at 7:46 AM, Bill Carson <bcarson@dciheat.com> wrote:

> Shannon,
>
> Find attached modified performance sheet.
>
> The particulate scrubber is not a venturi scrubber it is a coalescing scrubber. The flow is split into two (2) trains, each having a coalescing scrubber. Each coalescing scrubber consists of two mesh pads in the top of the packing and spray inside the heat recovery/scrubber vessel:
>
> 1) The lower mesh pad, a particulate coalesce, were the solid particulate is captured in water. Large droplets laden with solid particulate are entrained into the gas stream and finally impinge on the upper mesh pad.
>
> 2) The upper mesh pad, a mist eliminator, captures the water entrained from the lower mesh pad creating droplets large enough to fall countercurrent to the gas. The solid and the water drain out of the lower mesh pad, then finally drain into the packing below.
>
> The pressure drop across the coalescing scrubber ranges between 5.6 and 6.6 inches of water column, and the pressure drop across the mist eliminator ranges between 2.1 and 2.6-inches of water column.
>
> The mist eliminator mesh pad is continuously washed using between 65 and 123 gallons per minute each train. This is done to insure that buildup of solids does not occur in the mist eliminator.
>
> The coalescing scrubber will be periodically washed with water, if the pressure drop exceeds a specific point, say 6.6-inches of water column. The wash water rate of flow

will be between 200 and 350-gallons per minute. Only one coalescing scrubber pad will be washed at a time.

Hope this helps.

With Warmest Regards,

Bill Carson

CHIEF ENGINEER
Direct Contact LLC
Waste Heat Recovery... adding up to much more than a drop in the bucket!
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<062-preformance revD.pdf>

From:	Chris Durand
To:	Shannon Manoulian
Subject:	Re: DCLLC"s Preformance
Date:	Tuesday, August 14, 2012 5:22:55 PM
Attachments:	Flue Gas Pressure Drops.xlsx ATT00001.htm

Shannon,

Here is an additional table to help with the scrubber information. In the original application (2 X 450 gpm) I did not include the intermittent wash down water flow rate or the mist eliminator water flow (should have been included). The coalescing filter wash down water only occurs intermittently depending on the PM loading. If the PM is as estimated this wash down will likely occur about 5min out of each hour. If PM is lower then it will occur less. Also, when the coalescing filter is being washed the mist eliminator water for that section is turned off. This table now includes both. Also, the scrubber water pH will range from 9.5 to 11 per Bill's e-mail confirmation. Feel free to pass this along to Darrin with the other items or call me with question.

From: Shannon Manoulian [mailto:smanoulian@jbrenv.com]
Sent: Thursday, August 16, 2012 4:59 PM
To: Darrin Pampaian
Cc: Darrin Mehr; Kevin Schilling
Subject: RE: Permit Conditions Items

Darrin,

Please find attached a pdf document and Excel files to assist in answering your request below. Two items to note:

- An incorrect value for the TDS of the cooling tower water was used in the original submission. The memo in the pdf explains the discrepancy, and updated calculations are provided. The updated TDS values do not have significant impact on PTE or modeling results.
- I would like to discuss how the SCNR urea injection flow rate will be included in the permit conditions, and will provided further information once I have a better understanding of the information you require.

In addition, the maximum cooling tower circulation water flow rate can be found in the original application submittal, on the cooling tower design drawings included in Appendix E.

Please let me know if you have any questions, or need any additional information.

Best Regards,
Shannon

From: Darrin.Pampaian@deq.idaho.gov [mailto:Darrin.Pampaian@deq.idaho.gov]
Sent: Thursday, August 09, 2012 7:33 AM
To: Shannon Manoulian
Subject: Permit Conditions Items

Shannon,

I think I still need the following items (as discussed previously):

- Confirmation of the ammonia slip rate of 2 ppmv
- The corresponding NSCR urea injection flow rate range
- Confirmation of the scrubber venturi pressure drop range of 11 to 13 in H2O (the app. just says 12 in H2O)
- Confirmation of the scrubber liquor flow rate range of 440 to 460 gpm (the app. just says 450 gpm)
- Scrubber liquor pH range
- Confirmation of the maximum TDS of the cooling tower circulation water of 94 ppm (from the app.)
- Confirmation of the maximum cooling tower circulation water flow rate of 8,500 gpm (from the app.)

If I already have some of these just let me know.

Darrin Pampaian, P.E.
Staff Engineer
Idaho DEQ - Air Quality Division
1410 N. Hilton, Boise ID 83706-1255
ph: (208) 373-0587 fax: (208) 373-0340
Darrin.Pampaian@deq.idaho.gov

Email Attachments:

Excel Spreadsheets:	Flue Gas Pressure Drops.xlsx (40 KB)
	Ada Plant_081412_DEQ.xlsx (32 KB)
PDF file:	SNCR_TDS_Scrubber_081512.pdf (193 KB)

Flue Gas Pressure Drops.xlsx

8/16/12 submittal

Flue Gas Duct Section	Peak Power Production (Vessel 1 & 2 in service)				Off Peak Power Production (Only one vessel in service)			
	Pressure Drop (in w.c.)		**Scrubbing Water Flow rate (gpm)**		**Pressure Drop (in w.c.)**		**Scrubbing Water Flow rate (gpm)**	
	Min	Max	Min	Max	Min	Max	Min	Max
Mist Eliminator	2.1	2.6	130	246	0	1.3	65	123
Coalescing Filter (intermittent)	5.6	6.6	200	350	0	3.3	200	350
Structured Packing (cooled)	2	2	400	400	0	1	200	200
Structured Packing (non-cooled)	2	2	440	440	0	1	220	220
Wet Scrubber Continous			***970***	***1086***			***485***	***543***
Wet Scrubber Total	**11.7**	**13.2**	**1105**	**1313**	**0**	**6.6**	**685**	**893**
Indirect Condensing Economizer	2.5	2.5	n/a	n/a	0	0.25	n/a	n/a
Economizer	1.04	1.14	n/a	n/a	0	0.09	n/a	n/a
Evaporator	1.56	1.73	n/a	n/a	0	0.1	n/a	n/a
Super Heater 1	0.35	0.39	n/a	n/a	0	0.02	n/a	n/a
Super Heater 2	0.36	0.41	n/a	n/a	0	0.02	n/a	n/a
Screen	0.31	0.35	n/a	n/a	0	0.02	n/a	n/a
SNCR	2	2	n/a	n/a	0	0.13	n/a	n/a
Furnace	0	0	n/a	n/a	0	0	n/a	n/a
			n/a	n/a			n/a	n/a
HRSG Total	5.62	6.02	n/a	n/a	0	0.38	n/a	n/a
Secondary to HRSG Expansion								
Secondaries								
Turbulent Air Mixing and Damper								
Hot Gas Duct to Secondaries "Y"								
Hot Gas Duct								
Primary 1								
Primary 2								
Primary 3								
Primary 4								
Primary 5								
Primary 6								
Primary 7								
Primary 8								
Primary 9								
Primary 10								
Primary 11								
Primary 12								

Ada Plant_081412_DEQ.xlsx

8/16/12 submittal

Dynamis Energy WTE Facility
Thermal Conversion System - Hidden Hollow Landfill
Cooling Towers

Induced Draft Cooling Towers

Total Make-up to Unit:	470 gpm
Evaporation Loss:	372 gpm
Drift Loss:	0.26 gpm
Blowdown:	92 gpm

Cooling towers will operate at the same rates for both peak and off-peak thermal unit/boiler operation

Cooling Tower Emissions

	Total Liquid Drift Factor (lb/1000 gal)[b]	TDS Content Fraction	Emission Factor (lb/1000 gal)	Evaporation Rate (gal/hr)	PM/PM-10[a] Emission Rate lb/hr (lb/hr)	PM/PM-10[a] Emission Rate tpy[b] (tpy)
Cooling Tower	1.7	0.000975	0.001658	22,320	0.04	0.16
Total					**0.04**	**0.16**

[a]PM-10 emission factor assumed to be equal to PM emission factor. Assume PM2.5 = PM10.
[b]AP-42 Table 13.4-1 Total liquid drift for induced draft tower
TDS content in water from water analysis of makeup water.

Per Tower	0.0184977	0.081019926

Dynamis Energy WTE Facility
Thermal Conversion System
Thermal Conversion Unit - SNCR

			Hours	7am - 11pm	11pm-7am
Peak Exhaust Flow =	150,865	acfm @ 125.4F	Percent of day	0.67	0.33
Off-Peak Exhaust Flow =	39,100	acfm @ 134.5F			

			Conversions	1 ft3 =	0.028	m3
				1 g =	1000	mg
Maximum estimated ammonia slip (peak and off peak) =	10	ppmv		1 lb =	453.59	g
Maximum estimated ammonia slip @ peak flow =	6.39	mg/m3		1 hr =	60	min
Maximum estimated ammonia slip @ peak flow =	3.57	lb/hr				
Maximum estimated ammonia slip @ off-peak flow =	6.30	mg/m3				
Maximum estimated ammonia slip @ off-peak flow =	0.91	lb/hr				

$mg/m^3 = (ppmv)(12.187)(MW) / (273.15 + °C)$

where:

mg/m^3 =	milligrams of gaseous pollutant per cubic meter of ambient air
ppmv =	ppm by volume (i.e., volume of gaseous pollutant per 10^6 volumes of ambient air)
MW =	molecular weight of the gaseous pollutant
°C =	exhaust temperature in degrees Centigrade

Scrubber manufacturer guarantees 82% control of ammonia for incoming concentrations up to 3.57 lb/hr

Incoming concentration (lb/hr) =	3.57	lb/hr	
Estimated controlled ammonia emissions (lb/hr) =	0.64	lb/hr	
IDAPA 585 EL (lb/hr)	1.2	lb/hr	Therefore, no modeling required.
Estimated controlled ammonia emissions (mg/m3) =	1.15079	mg/m3	
Estimated controlled ammonia emissions (ppmv) =	1.80211	ppmv	

SNCR_TDS_Scrubber_081512.pdf

8/16/12 Submittal

From:	Chris Durand
To:	Shannon Manoulian
Subject:	Re: DCLLC"s Preformance
Date:	Tuesday, August 14, 2012 5:22:55 PM
Attachments:	Flue Gas Pressure Drops.xlsx ATT00001.htm

Shannon,

Here is an additional table to help with the scrubber information. In the original application (2 X 450 gpm) I did not include the intermittent wash down water flow rate or the mist eliminator water flow (should have been included). The coalescing filter wash down water only occurs intermittently depending on the PM loading. If the PM is as estimated this wash down will likely occur about 5min out of each hour. If PM is lower then it will occur less. Also, when the coalescing filter is being washed the mist eliminator water for that section is turned off. This table now includes both. Also, the scrubber water pH will range from 9.5 to 11 per Bill's e-mail confirmation. Feel free to pass this along to Darrin with the other items or call me with question.

August 27, 2012 Revised Modeling for $PM_{2.5}$ and PM_{10} SIL and NAAQS Compliance Demonstrations and Additional Information Regarding the Project

From: Shannon Manoulian [mailto:smanoulian@jbrenv.com]
Sent: Monday, August 27, 2012 8:30 AM
To: Kevin Schilling
Cc: Darrin Pampaian; Darrin Mehr
Subject: FW: DEQ questions regarding latest modeling submittals

Kevin,

I sent this on Friday, but the attachment was 13MB, so I think it is stuck in DEQ's mail system (it didn't get sent back to me though as undeliverable though). I will burn a CD with the model files and bring it over this morning.

Thanks!
Shannon

From: Shannon Manoulian
Sent: Friday, August 24, 2012 3:48 PM
To: 'Kevin.Schilling@deq.idaho.gov'
Cc: Darrin.Mehr@deq.idaho.gov; Darrin.Pampaian@deq.idaho.gov
Subject: RE: DEQ questions regarding latest modeling submittals

Hi Kevin,

I spoke with Dynamis. They have indicated that the County will include the access restricted area into the lease. The area shown in the model will be included within the lease area. The exact configuration is being reviewed by the County and I will provide confirmation of that to you as soon as possible.

In response to the other items, please see the responses in red below. Please let me know if you have any other questions/concerns, and again, I will get the revised lease info to you as soon as possible.

Hope you have a great weekend, thanks!
Shannon

2. The July 26, 2012 submittal from JBR to Darrin Pampaian, DEQ, and the July 30, 2012 revised modeling demonstration reflect an entirely new emission control method in the proposed waste-to-energy facility exhaust system—a selective non-catalytic reduction (SNCR) system which will be used to control NOx emissions. The SNCR system was described as a urea injection system that will form ammonia in the exhaust stream. The maximum 24-hour average ammonia slip emission rate anticipated for this source was not identified in either of these submittals.

DEQ received an email from JBR on August 16, 2012, with an attached EXCEL spreadsheet attached. The spreadsheet listed a controlled ammonia emissions rate of 0.643 lb/hr. If this rate is representative of facility-wide potential to emit on a 24-hour basis, then no modeling is required for TAP compliance as this rate is below the 1.2 lb/hr screening emissions level (EL) of Idaho Air Rules Section 585. Please verify this is the case.

Dynamis Energy/JBR Environmental Response (Notation by DEQ)

Kevin – this is the case. The controlled ammonia emissions rate of 0.643 lb/hr is the maximum hourly emissions rate, and is based on urea injection rate/ammonia slip for the peak operating conditions.

3. DEQ requested that Dynamis provide supporting documentation for the NO2/NOx ratio used for modeled NOx emissions from the thermal conversion unit. A response was provided in the July 30, 2012 cover letter and Section 3.1 – Non-Regulatory Defaults of the revised modeling report. JRB addressed the NO2/NOx ratio question with the following: "The NO2/NOx in-stack ratio of 0.15 for the thermal conversion unit was conservatively based on a blend of in-stack ratios for natural gas and diesel generator emissions as found in 'Assessment of Non-Regulatory Options in AERMOD, Specifically OLM and PVMRM' from San Joaquin Valley Air Pollution Control District. Based on syngas properties estimated by Dynamis, as well as source test data used to calculate emissions factors for the unit, the syngas produced by the thermal unit will be much more similar to natural gas than diesel. Therefore by using an average calculated based on the maximum NO2/NOx ratio for natural gas internal combustion engines and the recommended ratio for diesel internal combustion engines, the NO2/NOx in-stack ratio of 0.15 is reasonable and conservative. In reality, the thermal conversion unit functions in a similar manner to a thermal oxidizer. Thermal oxidizers are routinely used to enhance destruction of NOx, CO and SOx emissions at other facilities As a result, it is reasonable to assume that the thermal conversion unit will serve to help promote NOx destruction during operation which would result in lower NO2/NOx ratios than modeled. In addition, the NO2/NOx in-stack ratio is not expected to vary based on operating conditions."

DEQ's response to this assertion is as follows:

a) DEQ agrees that the thermal unit is more similar to a natural gas combustion unit than a diesel unit. However, DEQ is not confident, based on the submitted information, that NO2/NOx ratios for an internal combustion engine is reasonably representative or conservatively representative of NO2/NOx ratios of the thermal unit. More documentation of in-system NOx chemistry is needed.

b) DEQ agrees that the thermal unit may act similarly to a thermal oxidizer. However, the description provided does not confidently demonstrate that the current NO2/NOx ratio of 0.15 is conservative. The DEQ modeling group and a senior level permit writer were not aware of a thermal oxidizer's use as NOx or SOx control as claimed in the submittal. In fact, thermal oxidizers are a generator of NOx and SOx when treating a VOC rich gas stream and there have been considerable efforts into limiting NOx emissions from the operation of thermal oxidizers. Also, DEQ does not agree that if NOx is reduced the NO2/NOx ratio will be reduced. It may initially seem that NO2/NOx ratio reduction is an obvious conclusion from NOx reduction; however, without knowing the NO2/NO ratio, one cannot conclude that the NO2/NOx ratio will decrease with decreasing NOx. NOx is made up of both NO2 and NO, and if NO were reduced more than NO2, the NO2/NOx ratio could actually increase with a decrease in NOx.

c) A 0.05 NO2/NOx ratio was referenced for a mass burn waste-to-energy units from Malcom Pirnie, Inc. as stated in a September, 2010 revised modeling protocol to the Florida Department of Environmental Protection. The August version of the protocol stated a 0.1 NO2/NOx ratio and the September revision did not explain the change. Also, the agency responded to the protocol as follows: "A Tier 3 approach was submitted for NO2/NOx, but the submission was lacking documentation sufficient for approval. However, from previous discussions, this approach will not be used and a Tier 2 approach will likely only be needed. However, should a Tier 3 approach be needed additional information is required for review approval."

d) There was no discussion of how SNCR control of NOx will affect the NO2/NOx ratio.

Considering the lack of documentation supporting a 0.15 NO2/NOx ratio, considering that NO2 modeling results are very near the NO2 NAAQS, and considering SNCR control of NOx will be needed to demonstrate compliance and there was little evidence presented that supports an unchanged or decreased NO2/NOx ratio, DEQ will provide JBR/Dynamis the following options: 1) find better documentation that supports using a 0.15 NO2/NOx ratio; 2) use a different ratio and remodel NO2; 3) continue to use the 0.15 ratio but propose site specific measurement of the NO2/NOx ratio (either through source testing or continuous monitoring).

Dynamis Energy/JBR Environmental Response (Notation by DEQ)
Dynamis proposes (and will accept as a permit condition if necessary) to conduct site specific measurement of the NO2/NOx ratio, either through the initial source test, or through the CEMs system.

4. DEQ was informed on August 16, 2012, of revised PM2.5 and PM10 modeling performed in response to an identified emissions calculation error (memorandum titled "Dynamis Ada County WTE Facility Increase Cooling Tower Emission Rate"). The memo states:

"The revised emissions were input into the air dispersion model SIL analysis to determine any increased impacts due to the increased cooling tower emissions. Facility-wide 1st high 24-hr PM2.5 emissions increased from 8.62 ug/m3 to 8.69 ug/m3; 1st high 24-hr PM10 emissions increased from 10.8 ug/m3 to 10.87 ug/m3; annual PM2.5 emissions increased from 1.63 ug/m3 to 1.64 ug/m3.

"Dynamis reviewed the receptors exceeding the SIL for the increased PM2.5/PM10 impacts. The increase in PM2.5 and PM10 emissions and subsequent increase in ambient impacts from the cooling towers results in one additional receptor exceeding the 24-hr PM2.5 SIL and one additional receptor exceeding the 24-hr PM10 SIL. Based on the location and ambient concentration of these additional receptors, it is not anticipated that any exceedance of the 24-hr PM2.5 or 24-hr PM10 NAAQS would occur in the full impact modeling analysis. There were no additional receptors that exceeded the annual PM2.5 SIL."

Please provide the revised SIL modeling files for PM2.5 and PM10. Also, please revise the cumulative Impact analyses for PM2.5 and PM10 to include the new receptor and revised emissions rates.

Dynamis Energy/JBR Environmental Response (Notation by DEQ)
The revised SIL and cumulative impact analyses for PM2.5 and PM10 are attached to this email.

DEQ's Complete Email Request for Additional Information

From: Kevin Schilling
Sent: Sunday, August 19, 2012 8:24 PM
To: Shannon Manoulian
Cc: Darrin Mehr; Darrin Pampaian; William Rogers; Michael Simon
Subject: DEQ questions regarding latest modeling submittals

Shannon:

After review of the July 30 submittal of revised air impact analyses, there are several items DEQ requests that Dynamis address:

1. The ambient air boundary was altered in the July 30, 2012 submittal. Section 5.0 of the Modeling Report contains the entirety of documentation on the revisions to the ambient air boundary, but it does not contain an adequate level of detail for DEQ to understand the basis for the ambient air boundary determination. Please describe in detail the "controlled easement area" that is claimed as exempt from ambient air in addition to the Dynamis lease property.

If Dynamis is not leasing the additional property, DEQ greatly questions the legal ability to exclude the area from ambient air. Property not owned or leased is not under the control of the permittee, and thereby cannot be excluded from ambient air. If Dynamis does not have the legal ability to prohibit public (including Ada County Landfill staff) access to this additional "controlled easement area," the modeling analyses must be revised to reflect the original ambient air boundary based on the boundary of the leased property.

Modifying the area leased from Ada County would be the easiest method, from the standpoint of DEQ's review, to justify the change in the ambient air boundary. Any other method would definitely require a contractual agreement between Dynamis and Ada County, and then DEQ would evaluate the contract and determine whether it legally precludes access of Ada Country employees to the area and adequately conveys authority to the Dynamis to control such access on a permanent basis.

2. The July 26, 2012 submittal from JBR to Darrin Pampaian, DEQ, and the July 30, 2012 revised modeling demonstration reflect an entirely new emission control method in the proposed waste-to-energy facility exhaust system—a selective non-catalytic reduction (SNCR) system which will be used to control NOx emissions. The SNCR system was described as a urea injection system that will form ammonia in the exhaust stream. The maximum 24-hour average ammonia slip emission rate anticipated for this source was not identified in either of these submittals.

DEQ received an email from JBR on August 16, 2012, with an attached EXCEL spreadsheet attached. The spreadsheet listed a controlled ammonia emissions rate of 0.643 lb/hr. If this rate is representative of facility-wide potential to emit on a 24-hour basis, then no modeling is required for TAP compliance as this rate is below the 1.2 lb/hr screening emissions level (EL) of Idaho Air Rules Section 585. Please verify this is the case.

3. DEQ requested that Dynamis provide supporting documentation for the NO2/NOx ratio used for modeled NOx emissions from the thermal conversion unit. A response was provided in the July 30, 2012

cover letter and Section 3.1 – Non-Regulatory Defaults of the revised modeling report. JRB addressed the NO2/NOx ratio question with the following: "The NO2/NOx in-stack ratio of 0.15 for the thermal conversion unit was conservatively based on a blend of in-stack ratios for natural gas and diesel generator emissions as found in 'Assessment of Non-Regulatory Options in AERMOD, Specifically OLM and PVMRM' from San Joaquin Valley Air Pollution Control District. Based on syngas properties estimated by Dynamis, as well as source test data used to calculate emissions factors for the unit, the syngas produced by the thermal unit will be much more similar to natural gas than diesel. Therefore by using an average calculated based on the maximum NO2/NOx ratio for natural gas internal combustion engines and the recommended ratio for diesel internal combustion engines, the NO2/NOx in-stack ratio of 0.15 is reasonable and conservative. In reality, the thermal conversion unit functions in a similar manner to a thermal oxidizer. Thermal oxidizers are routinely used to enhance destruction of NOx, CO and SOx emissions at other facilities As a result, it is reasonable to assume that the thermal conversion unit will serve to help promote NOx destruction during operation which would result in lower NO2/NOx ratios than modeled. In addition, the NO2/NOx in-stack ratio is not expected to vary based on operating conditions."

DEQ's response to this assertion is as follows:

a) DEQ agrees that the thermal unit is more similar to a natural gas combustion unit than a diesel unit. However, DEQ is not confident, based on the submitted information, that NO2/NOx ratios for an internal combustion engine is reasonably representative or conservatively representative of NO2/NOx ratios of the thermal unit. More documentation of in-system NOx chemistry is needed.

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c) A 0.05 NO2/NOx ratio was referenced for a mass burn waste-to-energy units from Malcom Pirnie, Inc. as stated in a September, 2010 revised modeling protocol to the Florida Department of Environmental Protection. The August version of the protocol stated a 0.1 NO2/NOx ratio and the September revision did not explain the change. Also, the agency responded to the protocol as follows: "A Tier 3 approach was submitted for NO2/NOx, but the submission was lacking documentation sufficient for approval. However, from previous discussions, this approach will not be used and a Tier 2 approach will likely only be needed. However, should a Tier 3 approach be needed additional information is required for review approval."

d) There was no discussion of how SNCR control of NOx will affect the NO2/NOx ratio.

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decreased NO2/NOx ratio, DEQ will provide JBR/Dynamis the following options: 1) find better documentation that supports using a 0.15 NO2/NOx ratio; 2) use a different ratio and remodel NO2; 3) continue to use the 0.15 ratio but propose site specific measurement of the NO2/NOx ratio (either through source testing or continuous monitoring).

4. DEQ was informed on August 16, 2012, of revised PM2.5 and PM10 modeling performed in response to an identified emissions calculation error (memorandum titled "Dynamis Ada County WTE Facility Increase Cooling Tower Emission Rate"). The memo states:

"The revised emissions were input into the air dispersion model SIL analysis to determine any increased impacts due to the increased cooling tower emissions. Facility-wide 1st high 24-hr PM2.5 emissions increased from 8.62 ug/m3 to 8.69 ug/m3; 1st high 24-hr PM10 emissions increased from 10.8 ug/m3 to 10.87 ug/m3; annual PM2.5 emissions increased from 1.63 ug/m3 to 1.64 ug/m3.

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Please provide the revised SIL modeling files for PM2.5 and PM10. Also, please revise the cumulative Impact analyses for PM2.5 and PM10 to include the new receptor and revised emissions rates.

Please contact me or Darrin Mehr if you have any questions.

Regards,

Kevin Schilling
Stationary Source Air Modeling Coordinator
Idaho Department of Environmental Quality
208 373-0112

Revised Electronic Modeling Files Received via Hand-Delivery

Revision 5

August 27, 2012

(files not included)

From: Shannon Manoulian [smanoulian@jbrenv.com]
Sent: Tuesday, August 28, 2012 4:32 PM
To: Kevin Schilling
Cc: Darrin Mehr; Darrin Pampaian
Subject: RE: DEQ questions regarding latest modeling submittals

Hi Kevin,

Attached is the revised lease area. It is actually larger than the boundary used in the modeling.

Please let me know if you have any questions or concerns.

Thanks!
Shannon

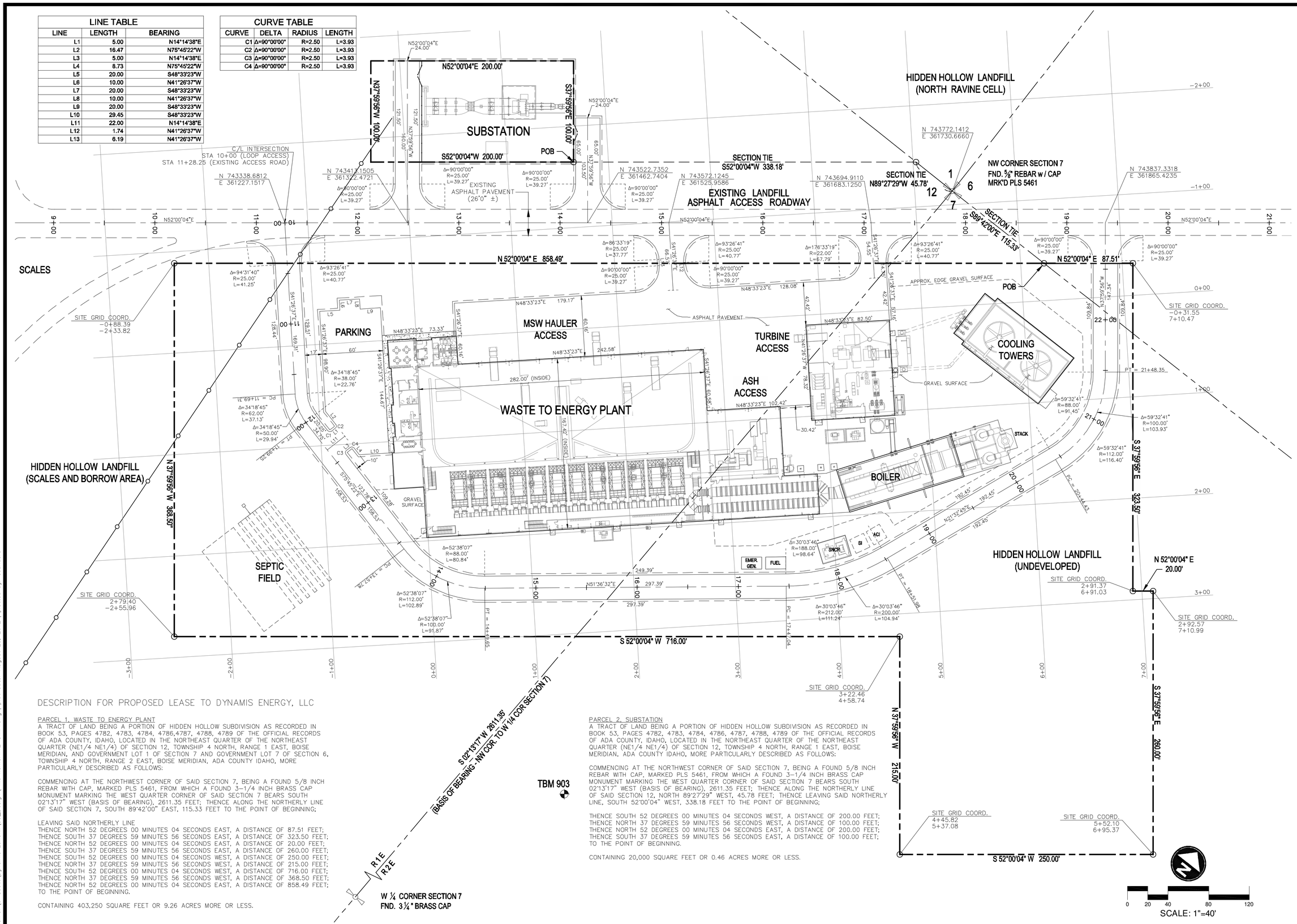
Attachment: WTE-DIMN-C4-082312.pdf

WTE-DIMN-C4-082312.pdf

August 28, 2012 submittal

LINE TABLE		
LINE	LENGTH	BEARING
L1	5.00	N14°14'38"E
L2	16.47	N75°45'22"W
L3	5.00	N14°14'38"E
L4	8.73	N75°45'22"W
L5	20.00	S48°33'23"W
L6	10.00	N41°26'37"W
L7	20.00	S48°33'23"W
L8	10.00	N41°26'37"W
L9	20.00	S48°33'23"W
L10	29.45	S48°33'23"W
L11	22.00	N14°14'38"E
L12	1.74	N41°26'37"W
L13	6.19	N41°26'37"W

CURVE TABLE			
CURVE	DELTA	RADIUS	LENGTH
C1	Δ=90°00'00"	R=2.50	L=3.93
C2	Δ=90°00'00"	R=2.50	L=3.93
C3	Δ=90°00'00"	R=2.50	L=3.93
C4	Δ=90°00'00"	R=2.50	L=3.93



DESCRIPTION FOR PROPOSED LEASE TO DYNAMIS ENERGY, LLC

PARCEL 1, WASTE TO ENERGY PLANT
A TRACT OF LAND BEING A PORTION OF HIDDEN HOLLOW SUBDIVISION AS RECORDED IN BOOK 53, PAGES 4782, 4783, 4784, 4786,4787, 4788, 4789 OF THE OFFICIAL RECORDS OF ADA COUNTY, IDAHO, LOCATED IN THE NORTHEAST QUARTER OF THE NORTHEAST QUARTER (NE1/4 NE1/4) OF SECTION 12, TOWNSHIP 4 NORTH, RANGE 1 EAST, BOISE MERIDIAN, AND GOVERNMENT LOT 1 OF SECTION 7 AND GOVERNMENT LOT 7 OF SECTION 6, TOWNSHIP 4 NORTH, RANGE 2 EAST, BOISE MERIDIAN, ADA COUNTY IDAHO, MORE PARTICULARLY DESCRIBED AS FOLLOWS:

COMMENCING AT THE NORTHWEST CORNER OF SAID SECTION 7, BEING A FOUND 5/8 INCH REBAR WITH CAP, MARKED PLS 5461, FROM WHICH A FOUND 3-1/4 INCH BRASS CAP MONUMENT MARKING THE WEST QUARTER CORNER OF SAID SECTION 7 BEARS SOUTH 02°13'17" WEST (BASIS OF BEARING), 2611.35 FEET; THENCE ALONG THE NORTHERLY LINE OF SAID SECTION 7, SOUTH 89°42'00" EAST, 115.33 FEET TO THE POINT OF BEGINNING;

LEAVING SAID NORTHERLY LINE
THENCE NORTH 52 DEGREES 00 MINUTES 04 SECONDS EAST, A DISTANCE OF 87.51 FEET;
THENCE SOUTH 37 DEGREES 59 MINUTES 56 SECONDS EAST, A DISTANCE OF 323.50 FEET;
THENCE NORTH 52 DEGREES 00 MINUTES 04 SECONDS EAST, A DISTANCE OF 20.00 FEET;
THENCE SOUTH 37 DEGREES 59 MINUTES 56 SECONDS EAST, A DISTANCE OF 260.00 FEET;
THENCE SOUTH 52 DEGREES 00 MINUTES 04 SECONDS WEST, A DISTANCE OF 250.00 FEET;
THENCE NORTH 37 DEGREES 59 MINUTES 56 SECONDS WEST, A DISTANCE OF 215.00 FEET;
THENCE SOUTH 52 DEGREES 00 MINUTES 04 SECONDS WEST, A DISTANCE OF 716.00 FEET;
THENCE NORTH 37 DEGREES 59 MINUTES 56 SECONDS WEST, A DISTANCE OF 368.50 FEET;
THENCE NORTH 52 DEGREES 00 MINUTES 04 SECONDS EAST, A DISTANCE OF 858.49 FEET;
TO THE POINT OF BEGINNING.

CONTAINING 403,250 SQUARE FEET OR 9.26 ACRES MORE OR LESS.

PARCEL 2, SUBSTATION
A TRACT OF LAND BEING A PORTION OF HIDDEN HOLLOW SUBDIVISION AS RECORDED IN BOOK 53, PAGES 4782, 4783, 4784, 4786, 4787, 4788, 4789 OF THE OFFICIAL RECORDS OF ADA COUNTY, IDAHO, LOCATED IN THE NORTHEAST QUARTER OF THE NORTHEAST QUARTER (NE1/4 NE1/4) OF SECTION 12, TOWNSHIP 4 NORTH, RANGE 1 EAST, BOISE MERIDIAN, ADA COUNTY IDAHO, MORE PARTICULARLY DESCRIBED AS FOLLOWS:

COMMENCING AT THE NORTHWEST CORNER OF SAID SECTION 7, BEING A FOUND 5/8 INCH REBAR WITH CAP, MARKED PLS 5461, FROM WHICH A FOUND 3-1/4 INCH BRASS CAP MONUMENT MARKING THE WEST QUARTER CORNER OF SAID SECTION 7 BEARS SOUTH 02°13'17" WEST (BASIS OF BEARING), 2611.35 FEET; THENCE ALONG THE NORTHERLY LINE OF SAID SECTION 12, NORTH 89°27'29" WEST, 45.78 FEET; THENCE LEAVING SAID NORTHERLY LINE, SOUTH 52°00'04" WEST, 338.18 FEET TO THE POINT OF BEGINNING;

THENCE SOUTH 52 DEGREES 00 MINUTES 04 SECONDS WEST, A DISTANCE OF 200.00 FEET;
THENCE NORTH 37 DEGREES 59 MINUTES 56 SECONDS WEST, A DISTANCE OF 100.00 FEET;
THENCE NORTH 52 DEGREES 00 MINUTES 04 SECONDS EAST, A DISTANCE OF 200.00 FEET;
THENCE SOUTH 37 DEGREES 59 MINUTES 56 SECONDS EAST, A DISTANCE OF 100.00 FEET;
TO THE POINT OF BEGINNING.

CONTAINING 20,000 SQUARE FEET OR 0.46 ACRES MORE OR LESS.

PROFESSIONAL ENGINEER
LICENSED
P-7141
STATE OF IDAHO
DOYLE PERGANDE

DATE:	AUGUST 23, 2012
DESIGNED BY:	STAFF
DRAWN BY:	STAFF
REVIEWED BY:	
PROJECT:	BOUNDARY REVISION
ISSUE:	

REVISIONS

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DYNAMIS ENERGY, LLC
ADA COUNTY LANDFILL WASTE TO ENERGY PLANT
PLAN SHEET
DIMENSIONING PLAN

DYNAMIS ENERGY

C4
SHEET 4 OF 8
V. 10 R. 9

path: C:\0-Scott\Dynamis Landfill\03_Design\ file name: WTE-DIMN.dwg | plot date: August 23, 2012 | plotted by: ssanders

Final response from JBR Environmental Consultants to K. Schilling DEQ regarding revisions modeling of pollutants with an annual averaging period (intermediate emails not included below):

From: Shannon Manoulian [mailto:smanoulian@jbrenv.com]
Sent: Monday, September 10, 2012 9:35 AM
To: Kevin Schilling
Cc: Darrin Mehr
Subject: RE: DEQ questions regarding annual modeling

Hi Kevin,

Thank you, the model files have been uploaded. Also attached to this email is a word document with the revised model results shown in the tables from the model report.

Thanks!
Shannon

Attachment: 090612 Model Results Tables.doc (64 KB)

From: Kevin.Schilling@deq.idaho.gov [mailto:Kevin.Schilling@deq.idaho.gov]
Sent: Thursday, September 06, 2012 9:43 AM
To: Shannon Manoulian
Cc: Darrin.Mehr@deq.idaho.gov
Subject: DEQ questions regarding annual modeling

Shannon,

I was reviewing the modeling files for annual impacts and TAP impacts and found a problem with the method used for emissions from the emergency generator. This error would have been found earlier but the modeling report does not describe in detail how the source in question was modeled.

Annual emissions were based on an allowable 500 hrs/yr. The hourly rate modeled was then calculated by dividing the annual emissions by 500 hrs/yr for NOx and SO2, and by 8760 hrs/yr for PM and TAPs. This would be appropriate if emissions were then modeled over 500 hours or 8760 hours. However, the calculated hourly emissions are modeled only over about 208 hours (the adjusted schedule used for conservatively modeling short-term emissions associated with engine testing - accomplished by using the MHRDOW7 function in AERMOD).

This error will not likely affect results to a substantial degree because of the magnitude of the emissions from the source. However, to achieve an application that is true and accurate, DEQ requests JBR/Dynamis to revise the modeling to reflect allowable emissions from the source, thereby providing an estimated ambient impact that is conservative. Correction of the error will involve rerunning modeling analyses for 3 TAPs, SIL analyses for annual PM2.5, NO2, and SO2, and cumulative impact analyses for PM2.5, NO2, and SO2.

Please contact me to discuss correction of the modeling and the anticipated schedule of completing these analyses.

Thank you,

Kevin Schilling
Stationary Source Air Modeling Coordinator
Idaho Department of Environmental Quality
208 373-0112.

090612 Model Results Tables.doc

September 10, 2012 Submittal

Table 1 SIL Model Predicted Impacts – Dynamis Facility SIL Analysis

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	SIL (ug/m^3)	NAAQS/ AAC/AACC (ug/m^3)	Modeled Output Value Used (5 years met data)	Met Data Used
PM_{10}	24-hour	10.87	5.0	150	1st high	5-yr concatenated
$PM_{2.5}$	24-hr	8.69	1.2	35	1st high	5-yr concatenated
	Annual	1.66	0.3	15	1st high	5-yr concatenated
NO_2	1-hr	142	7.5	188	1st high	5-yr concatenated
	Annual	9.11	1.0	100	1st high	One met file for each year of data
SO_2	1-hr	93.7	7.9	196	1st high	5-yr concatenated
	Annual	2.54	1.0	80	1st high	One met file for each year of data
Pb	Rolling 3-month average	0.017	n/a	0.15	1st high	5-yr concatenated
Benzene	Annual	8.3E-4	n/a	1.2E-01	1st high	5-yr concatenated
Formaldehyde	Annual	1.05E-3	n/a	7.7E-02	1st high	5-yr concatenated
Nickel	Annual	3.98E-3	n/a	4.2E-03	1st high	5-yr concatenated

Table 2 Full Impact Analysis Model Results - Scenario 1

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Concentration (ug/m^3)	NAAQS/ AAC/AACC (ug/m^3)	Modeled Value Used (5 years met data)
PM_{10}	24-hour	8.39	73	81.4	150	6th highest
$PM_{2.5}$	24-hr	8.69	19.3	28.0	35	Average 1st high for all meteorological years
	Annual	1.68	6.3	7.98	15	Average 1st high for all meteorological years
NO_2	1-hr	229.3	Background included in modeled impact	229.3	188	Max8th highest maximum daily 1-hr value for each year averaged for all years
	Annual	8.51	40	48.5	100	1st highest
SO_2	1-hr	64.7	33.1	97.8	196	Max 4th highest maximum daily 1-hr value for each year averaged for all years
	Annual	6.28	2.6	8.88	80	1st highest

Table 3 Full Impact Analysis Model Results - Scenario 2

Pollutant	Averaging Period	Modeled Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Concentration (ug/m^3)	NAAQS/ AAC/AACC (ug/m^3)	Modeled Value Used (5 years met data)
PM_{10}	24-hour	8.33	73	81.3	150	6th highest
$PM_{2.5}$	24-hr	8.69	19.3	28.0	35	Average 1st high for all meteorological years
	Annual	1.68	6.3	7.98	15	Average 1st high for all meteorological years
NO_2	1-hr	229.3	Background included in modeled impact	229.3	188	Max8th highest maximum daily 1-hr value for each year averaged for all years
	Annual	8.49	40	48.5	100	1st highest
SO_2	1-hr	64.7	33.1	97.8	196	Max 4th highest maximum daily 1-hr value for each year averaged for all years
	Annual	6.27	2.6	8.9	80	1st highest

Revised Electronic Modeling Files Uploaded to DEQ's ftp site

Revision 6

September 10, 2012

(files not included)