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Electronic Mail and Certified Mail to Addressee

May 11, 2022

Mr. Bryce Bird, Director
Division of Air Quality
Utah Department of Environmental Quality
195 North 1950 West
P.O. Box 144820
Salt Lake City, Utah 84114

RE: Regional Haze Phase 2 Information Request
Submittal of Supplemental Information
DAQP-042-22

Dear Mr. Bird:

Via an email and letter with a signature date of March 15, 2022 to US Magnesium LLC (USM), the Division of Air Quality (DAQ) transmitted its Request for Information ("Request" or "RFI") with a less than 30 day due date of April 11, 2022. Via an email and letter transmitted by USM on April 11, 2022, USM submitted its Initial Document Submittal and Request for Extension to Respond to (the) Remainder of the DAQ RFI. Via an email and letter dated April 29, 2022 to USM, DAQ transmitted approval of USM's request for extension and clarified the DAQ's information request. In accordance with the April 29, 2022 DAQ order, USM is providing information for Items 4. and 5.e. and an "analysis of the turbines used at the facility."

(4) Update the four-factor analysis to address flue gas temperatures at various points downstream of the spray dryer and the possibility of placing an SCR system downstream or near the stack exit.

USM Response: Refer to the attached letter addendum to the four-factor analysis prepared by GeoStrata dated May 11, 2022.

(5) Update the four-factor analysis with control cost estimates for the diesel engines, including the following:
    (e) evaluation of the cost of replacing the current diesel engines with newer Tier 4 compliant diesel engines or electric motors to power the pumps

USM Response: Refer to the attached letter addendum to the four-factor analysis prepared by GeoStrata dated May 11, 2022. In addition to an analysis of replacement with Tier 4 engines,the attached addendum includes an analysis of retrofitting pump station P-0 with distributed electric power and a motor drive. Pump station P-0 is the closest pump station to the operating plant's metered, transformed power. As is clear by GeoStrata's analysis, a new power distribution line and electric motor retrofit at P-0 is estimated at $32,478 per ton of NOx reduction. Therefore, USM did not pursue an analysis of electrical power / motors at the progressively more costly / distant pump stations.

“Analysis of the turbines used at the facility”

USM Response: USM has continued to explain very clearly that the turbines originally installed at spray dryers 01, 02 and 03 are fully-integrated into the process of dehydrating concentrated brine and producing magnesium chloride as a solid salt (spray dried powder or “SDP”). The construct of the USM air emission inventory (AEI) dating back to the “TEMPO” Excel file format and now loaded into the SLEIS system may be the source of DAQ’s current staff confusion. As a fact, the sources of spray dryer natural gas combustion emissions (Emission Unit Description = “Turbine, 01 plus duct burner 01”) and hydrochloric acid and particulate matter emissions (Emission Unit Description = “Stack, 01 spray dryer”) report to the single spray dryer 01 stack within the 250-foot main stack at USM. Spray dryers 02 and 03 are reported with the same year-specific inputs as for spray dryer 01. The construct of the AEI merely separates the calculation of spray dryer natural gas combustion emissions from the hydrochloric acid and particulate matter emissions.

- Spray Dryer Combustion Emission Calculation: Million cubic feet of natural gas consumed annually * AP-42 Section 3.1, Table 3.1-1 and 3.1-2a emission factors = annual emissions for NOx and criteria pollutants for that spray dryer
- Spray Dryer HCl and PM Emissions Calculation: Operating hours * annual stack testing results in pounds per hour = annual hydrochloric acid and particulate matter emissions for that spray dryer

Although the downstream processes (spray dry tower, cyclones, pre-heater / concentrator tanks) and wet scrubbing system may capture and remove some of the natural gas combustion emissions, USM has taken a maximally conservative approach to its AEI calculations (i.e., zero removal in the spray dryer process and wet scrubber). In order to be responsive to this item, USM is providing the “INSTRUCTIONS GEK-7588, GAS TURBINE POWER PLANT, TURBINE NOS. 214034, 214035, & 214036, furnished NATIONAL LEAD COMPANY, MAGNESIUM DIVISION, ROWLEY, UTAH” dated 11/70 as a second attachment to this transmittal.

If DAQ staff have further questions on the integration of natural gas combustion into spray dryer operation, USM requests that DAQ staff schedule a visit to the Rowley plant to confirm the descriptions previously provided and contained herein.

Contact me at (801) 532-1522 ext. 1355 should you have questions regarding this information.

Signed,

Rob J Hartman

Rob Hartman, P.G.
Environmental Manager
US Magnesium LLC

Attachments

Cc: Chelsea Cancino, DAQ
Mike Zody, PB&L
Mike Vorkink, GeoStrata
Jon Peaden, Geo Strata

GeoStrata Engineering & Geosciences
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May 11, 2022

Utah Division of Air Quality
Attention: Mr. Bryce C. Bird, Director
195 North 1950 West
Salt Lake City, UT 84114-4880

RE: Regional Haze Phase 2 Information Request Initial Document Submittal and Request for Extension to Respond to Remainder

Mr. Bird:

In a letter dated April 29, 2022, the Utah Division of Air Quality (DAQ) requested that the US Magnesium provide information related to review comments of the GeoStrata report titled "Regional Haze 2nd Implementation Period Four-Factor Analysis US Magnesium LLC, Rowley Plant - Tooele County". US Magnesium requested that GeoStrata respond to selected review comments in the information Order. This letter is an addendum to the Four-factor Analysis and addresses the following comments as requested. Please feel free to contact our office with any questions.

Comment 4. *Update the four-factor analysis to address flue gas temperatures at various points downstream of the spray dryer and the possibility of placing an SCR system downstream or near the stack exit.*

As directed by the DAQ, GeoStrata has updated the four-factor analysis to include re-evaluation of a Selective Catalytic Reduction system at various points downstream of the primary natural gas combustion that feeds hot gas to the spray dryer to dehydrate brine and produce powdered magnesium chloride (spray-dried powder or "SDP"). The hot gas introduced into the spray dryers is in the range of 900 to 1,100 ^{o}F. The plant design and construction by National Lead Company in 1971 included General Electric turbines to opportunistically generate power and use the hot exhaust gas to produce SDP in the spray dryers. The spray dryers are fully operational with natural gas fired burners to heat the gas stream <u>without</u> a turbine as is currently the case at Spray Dryer 2. Exhaust from the spray dryers is generally at a temperature in the range of 550 to 800 ^{o}F and proceeds to cyclones that separate and collect SDP. Installing the SCR at this point would not be technically feasible since the SDP still remains in the exhaust gas that would affect the recovery of the product and reduce the efficiency of the SCR system by blinding the catalyst with the particulate matter.

The post-cyclones exhaust gas then enters the brine pre-heater / concentrator tanks to preheat brine (prior to feed into the spray dryers) and capture carry-over SDP from the cyclones for recovery back in the spray dryers. The pre-heating and concentrators are directly related to the production process of the spray dryers. The SCR is not technically feasible since the spray dryers would require additional heat energy to maintain the production process and would increase NOX emissions in addition to other issues with hydrochloric acid vapors in the exhaust gas.

Upon exiting the pre-heater / concentrator tanks, the gas temperature is in the range of 250 to 300^o F. A SCR control devise is possible to use for removal of NO_x emissions without affecting the magnesium production process; however, there are other concerns due to the temperature and particulates in the exhaust gas. The gas then enters the spray dryer scrubbers (wet, vertical packed bed scrubbers) to remove particulate and hydrochloric acid vapors. The scrubber exhaust temperature is in the range of 130 to 150 ^{o}F. At these temperatures, the SCR system would be inefficient to the point of only minimal reduction of NOx would occur without reheating the exhaust and consequently increasing NO_X emissions.

Although there are major concerns of using this technology at any point on the exhaust after the spray dryers, GeoStrata has reviewed the feasibility of an SCR System after the pre-heater/concentrator tanks. Evaluating the cost for a SCR for this process is challenging due to the reduced temperature and the remaining hydrochloric acid vapors that are in the exhaust gas. The EPA's Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR) was used to estimate the costs of retrofitting the spray dryer exhaust with an SCR[1]; the cost values are based on the 2018 annual average Chemical Engineering Plant Cost Index (CEPCI) value of 603.1. The summary of the results is listed below in Table 1, with the detailed results found in Attachment A.

[1] The detailed inputs and outputs of the EPA cost estimation tool can be found in Appendix A.

Table 1: Summary of SCR Retrofit Cost for Gas Turbine Post Spray Dryer

CAPITAL COSTS for each TURBINE			
Direct Costs		**Indirect Annual Costs**	
SCR System	$96,128.00	Administrative Charges	$2,800.00
		Capital Recovery Costs	$245,838.00
Total	$96,128.00	**Total**	$248,638.00
ANNUAL COSTS		**Totals**	
Direct Costs		Interest rate	3.25%
Maintenance (.005 x TCI)	$23,332.00	CAPITAL RECOVERY FACTOR	0.0527
Annual Reagen Cost	$35,680.00	Life of Control (yrs)	30
Annual Electricity Cost	$21,393.00	Total Capital Investments	$4,666,473.00
Annual Catalyst Replacement Cost	$15,723.00	Total Annual Costs	$344,766.00
Total	$96,128.00	Total Annual Cost	**$344,766.00**

TOTAL CAPITAL COST FOR 3 SCR SYSTEMS			
Total	**$288,384.00**	**Total Annual Cost**	**$1,034,298.00**

According to the EPA SCR Fact sheet[2] this system is most efficient when operated at temperatures ranging from 480° F to 800° F. At temperatures below 300° F efficacy drops to 20% removal of NOx. In addition, at this temperature, there is the risk of ammonia slip where the catalyst introduced to the exhaust gas does not react with the NOx and is included in the stack emissions. Another concern is the presence of hydrochloric acid vapors in the exhaust gas. Halogens that are in the exhaust gas can poison the catalyst and reduce the efficiency of the SCR and/or increase the maintenance cost and could potentially increase NOx emissions. However, despite these major concerns with the feasibility of a SCR system the cost effectiveness based on 2018 dollars is listed in Table 2.

Table 2: SCR Retrofit Cost Effectiveness for Spray Dryers 01, 02 and 03

	Total Annual Cost for 3 Units ($/yr)	Control Efficiency	NO_X Emissions Reduction (all 3 units combined)	Cost Effectiveness ($/ton removed)
SCR Costs	$1,034,298	20%	84	$12,316

\2 See EPA Website: https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

The costs associated with installing an SCR system on the hot-gas stream entering the spray dryers and cyclones would not be considered economically feasible let alone technologically feasible. As a result, the use of an SCR system for NO_X control has been ruled out as a viable retrofit option for NO_X control.

Comment 5e. *Update the four-factor analysis with control cost estimates for the diesel engines including…evaluation of the cost of replacing the current diesel engines with newer Tier 4 compliant diesel engines or electric motors to power the pumps*

GeoStrata evaluated the cost of replacing the existing diesel engines with a similarly rated diesel-powered engine that meets the Tier 4 Requirements. The engines make and models are listed below:

- 14 - Caterpillar 3406 (420 hp)
- 13 – Caterpillar 3208 (225 hp)
- 1 – Cummings C-9 (285 hp)
- 1 – Caterpillar 3306 (225 hp)
- 1 – Caterpillar 3304 (90 hp)

A replacement engine of similar horsepower and meets the requirements of a Tier 4 engine are provided in Tables 3 and 4. The Cat C15 Tier 4 Final engine will replace the Caterpillar 3406 and the Cummins C-9.3 for a total of fifteen engines replaced. The 2015 Caterpillar C9 Diesel Engine Power Unit, Tier 4 Final engine was used to estimate the replacement cost of the Caterpillar 3208, 3306 and 3304 engines for a total of an additional fifteen engines replaced. Specification of the replacement engines are included in Attachment B

Table 3: Summary of Replacement Engine Cost for 3406 Engine

CAPITAL COSTS CAT C9.3 Engine (Replace 3208)			
Direct Costs		**Installation Costs**	
Newer Tier 4 Engine	$78,500.00	Surface Equipment	$5,000.00
		Startup	$250.00
		Contractor Fee	$1,500.00
Taxes	$5,691.25	Contingency	$800.00
		Testing	$250.00
Total	$84,191.25	**Total**	$7,800.00
ANNUAL COSTS		**Totals**	
Direct Costs		Interest rate	3.25%
Maintenance (hrs @ $)	52 @ $130	CAPITAL RECOVERY FACTOR	0.0527
Cost of Maintenance hours	$6,760.00	Life of Control (yrs)	30
Maintenance Parts	$2,500.00	Total Capital Costs	$91,991.25
Fuel: Based on 2018 hours @ 1693 and 12.7 gal/hr	$70,953.00	Annualized Capital	$4,846.26
		Annual Maintenance Cost	$80,213.00
Total	$80,213.00	Total Annual Cost	**$85,059.26**
Total for 15 Engines	$1,203,195.00		$1,275,888.85

Table 4: Summary of Replacement Engine Cost for 3208 Engine

CAPITAL COSTS CAT C15 HP Engine (Replace 3406)			
Direct Costs		**Installation Costs**	
Newer Tier 4 Engine	$115,900.00	Surface Equipment	$5,000.00
		Startup	$250.00
		Contractor Fee	$1,500.00
Taxes	$8,402.75	Contingency	$800.00
		Testing	$250.00
Total	$124,302.75	**Total**	$7,800.00
ANNUAL COSTS		**Totals**	
Direct Costs		Interest rate	3.25%
Maintenance (hrs @ $)	52 @ $130	CAPITAL RECOVERY FACTOR	0.0527
Cost of Maintenance hours	$6,760.00	Life of Control (yrs)	30
Maintenance Parts	$2,500.00	Total Capital Costs	$132,102.75
Fuel: Based on 2018 baseline hours @ 1693 and 24 gal/hr	$134,085.60	Annualized Capital	$6,959.40
		Annual Maintenance Cost	$143,345.60
Total	$143,345.60	Total Annual Cost	**$150,305.00**
Total for fifteen engines	$2,150,184.00		$2,254,575.00

Continuing with the simplified model used in the SIP, if each of the thirty engines play an equal role in 71.65 tons of NO_X emitted annually from the diesel engines on site, then all engines under a Tier 4 emissions would have approximately 8.5 tons of NOx or about an 88% reduction in NOx emissions. A summary of the cost breakdown per engine and as an entire facility can be found in Table 5.

Table 5: Cost Effectiveness for Engine Replacements

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness for all Engines ($/ton removed)
Per Engine Basis (3406)	**$85,059**	88%	2.1	$55,906
Per Engine Basis (3208)	**$150,305.50**	88%	2.1	
All Engines	$3,530,463.85	88%	63.15	

The emissions reductions from replacement of all engine units cannot make up the costs to purchase the engines. The replacement of all units has been ruled out as a viable option for NO_X control.

GeoStrata has also evaluated the cost of converting the pumps to electrical power. For the purposes of this evaluation the cost of constructing the necessary electrical infrastructure was estimated for pumps located closest to the available electrical sources. Table 6 is a summary of the capital cost and annualized cost for the electrical conversion of the pumps at one location Identified at P-0. A breakdown of the total conversion cost to construct the electrical lines and pumps is included in Attachment C.

Table 6: Summary of Cost for P-0 Pump Engine Conversion to Electrical Pump

CAPITAL COSTS for Electric Conversion				
Direct Costs			**Installation Costs**	
			Total Conversion Costs for Construction	$571,200.00
Total	$0.00		**Total**	$571,200.00
ANNUAL COSTS			**Totals**	
Direct Costs			Interest rate	3.25%
Maintenance (hrs @ $)	20 @ $130		CAPITAL RECOVERY FACTOR	0.0527
Cost of Maintenance hours	$2,600.00		Life of Control (yrs)	30
Maintenance Parts	$2,500.00		Total Capital Costs	$571,200.00
Electrical Costs 2018 Base year hours @ $0.10/Kwh	$33,013.00		Annualized Capital	$30,091.80
			Annual Maintenance Cost	$38,113.00
Total	$38,113.00		Total Annual Cost	**$68,204.80**

Cost evaluation the pump located at P-0 is used in this evaluation because it is the closest pump group to the electrical source. Conversion of the other pump groups would have similar costs as additional power poles and infrastructure would be required to power the electric pumps. Replacement of the diesel engines will eliminate NO_x emission from the operation of the pump. A summary of the cost breakdown at the P-0 location can be found in Table 7.

Table 7: Cost Effectiveness for Conversion to Electrical Pumps

	For Location P-0 ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
Electrical Pump Construction Cost	$68,204.80	100%	2.1	$32,478

The NOx emissions elimination from converting the pumps to electrical power cannot make up the costs to construct the electrical infrastructure needed to power the pumps. This cost also does not include the cost to establish easements / right of ways for the electrical utilities that would have to cross non-US Magnesium owned property. The use of electrically powered pumps has been ruled out as a viable option for NO_X control and are not economically feasible.

Respectfully submitted,

GeoStrata

Jon Peaden
Environmental Scientist

Mike Vorkink, P.G.
Senior Geologist

Attachment A

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 12.7 MWh

What is the higher heating value (HHV) of the fuel? 1,030 Btu/scf

*HHV value of 1030 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MW output? 106,680 MW/year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 4230 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	0	0.31	8,730
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 350 days

Number of days the boiler operates (t_{plant}) 350 days

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

Inlet NO_x Emissions (NOx_{in}) to SCR	0.32 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
NOx Removal Efficiency (EF) provided by vendor	20 percent	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours		
Estimated SCR equipment life * For utility boilers, the typical equipment life of an SCR is at least 30 years.	30 Years*	Gas temperature at the SCR inlet (T)	300 ^oF
		Base case fuel gas volumetric flow rate factor (Q_{fuel})	150000 ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	29 percent*		
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*		
Number of days reagent is stored ($t_{storage}$)	14 days		

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	603.1 2018 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	
Reagent ($Cost_{reag}$)	3.56	$/gallon for a 29 percent solution of ammonia	* $3.56/gallon is a default value for the reagent cost. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0390	$/kWh*	* $0.0390/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	160.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*	* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	3.56	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	104	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	111,252	MW/year	
Estimated Actual Annual MW Output (Boutput) =		106,680	MW/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.96	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8400	hours	
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	20.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	6.66	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	27.99	tons/year	139.96416
NOx removal factor (NRF) =	EF/80	0.25		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	10,234,448	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$	11,204.10	/hour	
Residence Time	$1/V_{space}$	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.17		
Atmospheric pressure at sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.6	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.323	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	913.46	Cubic feet

Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	10,661	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	12,260	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	110.7	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SFR \times MW_R)/MW_{NOx}$ =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	9	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	401	gallons (storage needed to store a 14 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0527

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	65.30	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 80,000 \times (200/B_{MW})^{0.35} \times BMW \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 60,670 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,270 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 9,760 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,275 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,082 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$4,666,473	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$96,128	in 2018 dollars
Indirect Annual Costs (IDAC) =	$248,638	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$344,766	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$23,332	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$35,680	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$21,393	in 2018 dollars
Annual Catalyst Replacement Cost =		$15,723	in 2018 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$96,128	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,800	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$245,838	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$248,638	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$344,766	per year in 2018 dollars
NOx Removed =	28	tons/year
Cost Effectiveness =	$12,316	per ton of NOx removed in 2018 dollars

Attachment B

C9.3 ACERT™ Industrial Power Unit

Tier 4 Final, Stage IV Technology

224-298 bkW/300-400 bhp @ 1800-2200 rpm

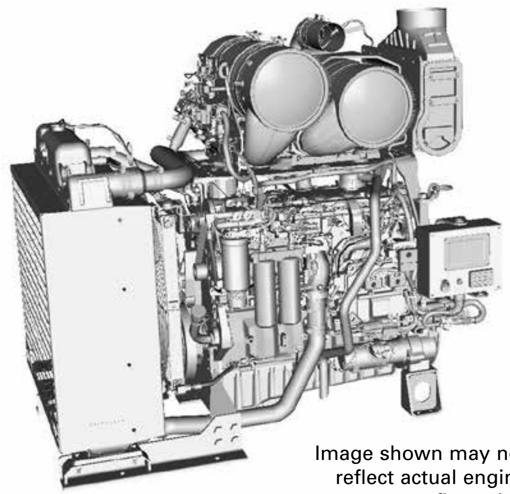


Image shown may not reflect actual engine configuration

CAT® ENGINE SPECIFICATIONS

I-6, 4-Stroke-Cycle Diesel

Bore	115 mm (4.53 in)
Stroke	149 mm (5.87 in)
Displacement	9.3 L (567.5 in³)
Aspiration	Turbocharged-Aftercooled
Compression Ratio	17.0:1
Combustion System	Direct Injection
Rotation (from flywheel end)	Counterclockwise
Capacity for Liquids	
Cooling System	64 L (68 U.S. qts)
Lube System (refill)	30 L (31.7 U.S. qts)
Engine Weight, Net Dry (standard configuration without oil, cooling, clutch, compressor A/C) (approximate)	1678 kg (3699 lb)

FEATURES

Emissions
Designed to meet U.S. EPA Tier 4 Final, EU Stage IV emission standards.

Reliable, Quiet, and Durable Power
World-class manufacturing capability and processes coupled with proven core engine designs assure reliability, quiet operation, and many hours of productive life.

High Performance
Simple and efficient turbocharger with balance valve provides optimal air management and improved fuel efficiency.

Fuel Efficiency
Fuel consumption optimized to match operating cycles of a wide range of equipment and applications.

Fuel & Oil
Tier 4 Final, Stage IV engines require Ultra Low Sulfur Diesel (ULSD) fuel containing a maximum of 15 ppm sulfur, and new oil formulations to support the new technology. Cat® engines are designed to accommodate B20 biofuel. Your Cat dealer can provide more information regarding fuel and oil.

Broad Application Range
Industry-leading range of factory configurable ratings and options for agricultural, materials-handling, construction, mining, forestry, waste, and other industrial applications.

Package
Exceptional power density enables standardization across numerous applications. Available factory-installed configurations: full package, including radiator and Clean Emissions Module (CEM); package with CEM, but no radiator; and package with radiator installed, but CEM shipped loose.

Low-Cost Maintenance
Worldwide service delivers ease of maintenance and simplifies the servicing routine. Minimum 5000-hour diesel particulate filter (DPF) ash service interval enables low-cost maintenance. Capable of optimal oil change intervals of up to 500 hours, depending on rating, application, operating conditions, and maintenance practices. Engine is designed for a B10 life of up to 10,000 hours. The S•O•S℠ program is available from your Cat dealer to determine oil change intervals and provide optimal performance.

Quality
Every Cat engine is manufactured to stringent standards in order to assure customer satisfaction.

World-class Product Support Offered Through Global Cat Dealer Network

- Scheduled maintenance, including S•O•S℠ sample
- Customer Support Agreements (CSA)
- Caterpillar Extended Service Coverage (ESC)
- Superior dealer service network
- Extended dealer service network through the Cat Industrial Service Distributor (ISD) program

Web Site: For additional information on all your power requirements, visit www.cat-industrial.com.

STANDARD ENGINE EQUIPMENT

Control System
Electronic control system, over-foam wiring harness, automatic altitude compensation, power compensated for fuel temperature, remote fan control, configurable software features, engine monitoring system SAE J1939 broadcast and control, integrated Electronic Control Unit (ECU)

Cooling System
Vertical outlet thermostat housing, centrifugal water pump, guidance on cooling system design available through your dealer to ensure equipment reliability

Exhaust System
Mid-mount turbocharged system with front exhaust configuration

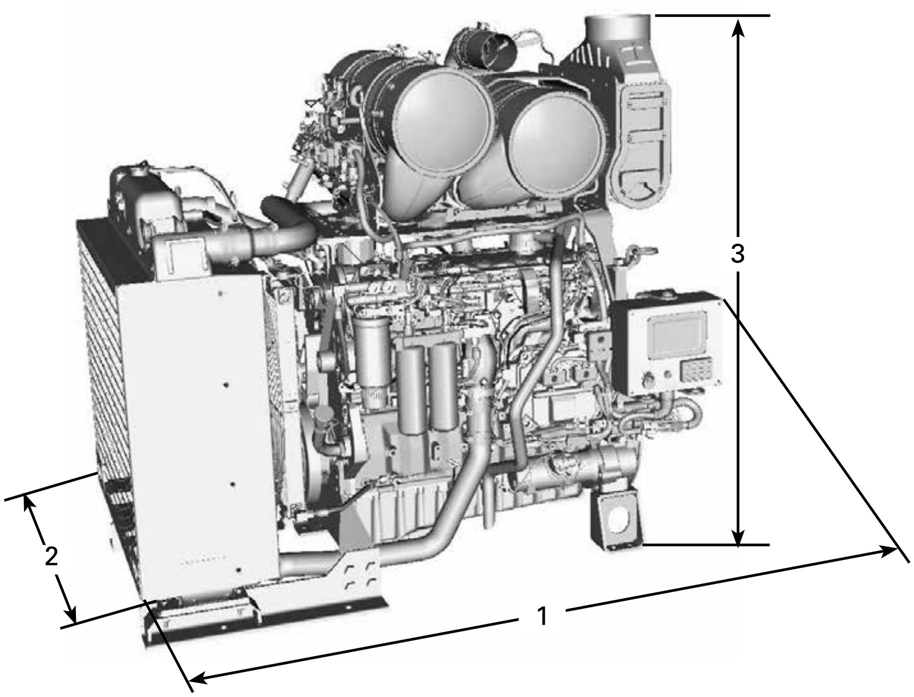
Flywheels and Flywheel Housing
SAE No. 1 and SAE No. 2 flywheel housings; available SAE 1 power take-off housing with optional SAE A, SAE B, and SAE C power take-off drives; engine power can also be taken from the front of the engine with optional attachments

Fuel System
Electronic high pressure common rail; primary fuel filter, secondary fuel filters, fuel transfer pump, electronic fuel priming

Lube System
Open crankcase ventilation system with fumes disposal (optional OCV filter system); oil cooler, oil filler, oil filter, oil dipstick, oil pump (gear-driven); choice of sumps (front, rear, and center)

General
Paint: Cat yellow

DIMENSIONS



(1) Length — 2042 mm (80.4 in) (2) Width — 1094 mm (43.1 in) (3) Height — 1741 mm (68.5 in)

Note: Final dimensions dependent on selected options

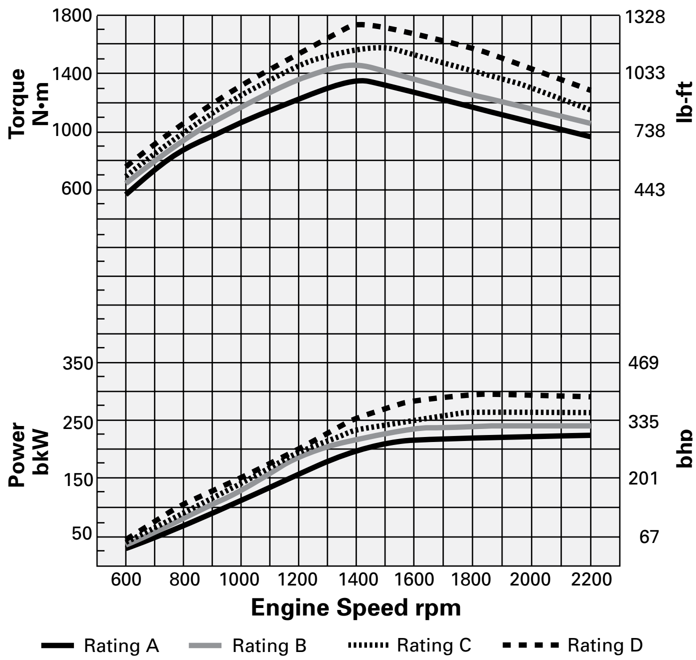
C9.3 ACERT™
Industrial Power Unit

Tier 4 Final, Stage IV Technology
224-298 bkW/300-400 bhp @ 1800-2200 rpm

PERFORMANCE DATA — PRELIMINARY

Turbocharged-Aftercooled — 1800-2200 rpm

Rated Speed



Speed Range

Rating	Aspiration	Rated Speed rpm	Rated Power bkW	Rated Power bhp	Speed rpm	Peak Torque N•m	Peak Torque lb-ft
A	TA	2200	224	300	1400	1369	1009
B	TA	2200	242	325	1400	1484	1095
C	TA	2200	261	350	1400	1596	1177
D*	TA	2200	290	389	1400	1719	1268

*298 bkW (400 bhp) @ 2000 rpm also available

RATING DEFINITIONS AND CONDITIONS

IND-A (Continuous) for heavy duty service where the engine is operated at maximum power and speed up to 100% of the time without interruption or load cycling.

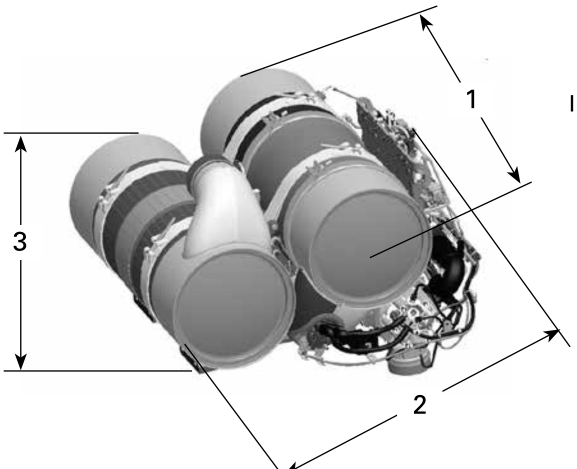
IND-B for service where power and/or speed are cyclic (time at full load not to exceed 80%).

IND-C (Intermittent) is the horsepower and speed capability of the engine where maximum power and/or speed are cyclic (time at full load not to exceed 50%).

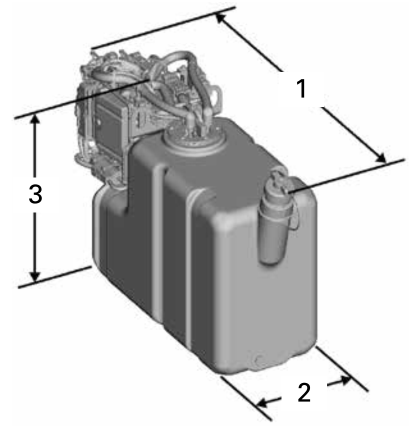
IND-D for service where maximum power is required for periodic overloads.

Rating Conditions are based on SAE J1995, inlet air standard conditions of 99 kPa (29.31 in Hg) dry barometer and 25°C (77°F) temperature. Performance measured using a standard fuel with fuel gravity of 35° API having a lower heating value of 42 780 kJ/kg (18,390 btu/lb) when used at 29°C (84.2°F) with a density of 838.9 g/L.

AFTERTREATMENT CONFIGURATION



Images shown may not reflect actual aftertreatment.



STANDARD CONFIGURATION SHOWN
Approximate Size and Weight
(1) Length — 885 mm (34.8 in)
(2) Width — 870 mm (34.25 in)
(3) Height — 570 mm (22.4 in)
Weight — 212 kg (467 lbs)

CEM Configuration
Standard configuration includes Diesel Particulate Filter (DPF), Diesel Oxidation Catalyst (DOC), Selective Catalytic Reduction (SCR), and supporting structure. Multiple configuration options available for aftertreatment system.

MAXIMUM 48.4 L (51.1 U.S. qt)
PETU CONFIGURATION SHOWN
Approximate Size and Weight
(1) Length — 854 mm (33.6 in)
(2) Width — 287 mm (11.3 in)
(3) Height — 551 mm (21.7 in)
Weight, dry — 19.42 kg (42.8 lbs)

PETU Configuration
Pump Electronic Tank Unit (PETU), consisting of Diesel Exhaust Fluid (DEF) tank with integrated Dosing Control Unit (DCU). Available in different volume configurations.

Contact your Cat dealer for additional information.

AFTERTREATMENT FEATURES

Regeneration: Cat Regeneration System maximizes fuel efficiency during regeneration. Transparent regeneration maximizes uptime.

Mounting: Industrial power units have standard horizontal mounting.

Service: Minimum 5000-hour diesel particulate filter ash service interval. PETU filter service is 5000 hours. PETU DEF capacity up to 48.4 liters (51.1 U.S. quarts).

Available in 12V or 24V systems

STANDARD EMISSIONS CONTROL EQUIPMENT

Cat Regeneration System
CEM: Clean Emissions Module
DOC: Diesel Oxidation Catalyst
ECU: Aftertreatment Electronic Control Unit
DPF: Diesel Particulate Filter
NRS: NOx Reduction System
SCR: Selective Catalytic Reduction
PETU: Pump Electronic Tank Unit

LEHH0544-01 (3-13)

C15 ACERT™
Industrial Power Unit
Tier 4 Final, Stage IV Technology
354-433 bkW/475-580 bhp @ 1800-2100 rpm

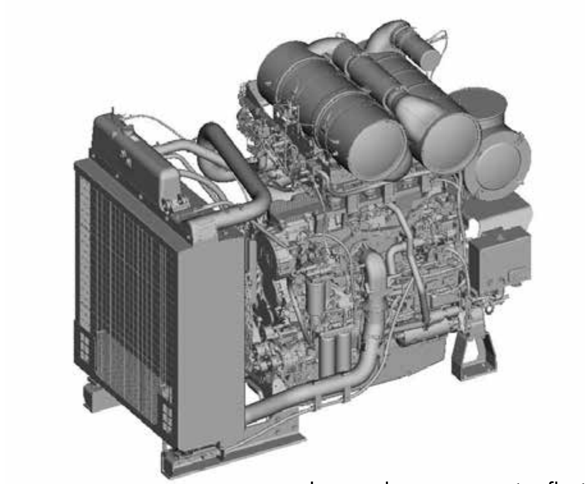


Image shown may not reflect actual engine configuration

CAT® ENGINE SPECIFICATIONS

I-6, 4-Stroke-Cycle Diesel

Bore	137 mm (5.39 in)
Stroke	171 mm (6.73 in)
Displacement	15.2 L (927.6 in³)
Aspiration	Turbocharged-Aftercooled
Compression Ratio	17.0:1
Combustion System	Direct Injection
Rotation (from flywheel end)	Counterclockwise
Capacity for Liquids	
Cooling System	90.9 L (96 U.S. qts)
Lube System (refill)	38-72 L (40-76 U.S. qts)
Engine Weight, Net Dry (standard configuration without oil, cooling, clutch, compressor A/C) (approximate)	2650 kg (5842 lbs)

FEATURES

Emissions
Designed to meet U.S. EPA Tier 4 Final, EU Stage IV emission standards.

Reliable, Quiet, and Durable Power
World-class manufacturing capability and processes coupled with proven core engine designs assure reliability, quiet operation, and many hours of productive life.

High Performance
Simple and efficient turbocharger with balance valve provides optimal air management and improved fuel efficiency.

Fuel Efficiency
Fuel consumption optimized to match operating cycles of a wide range of equipment and applications.

Fuel & Oil
Tier 4 Final, Stage IV engines require Ultra Low Sulfur Diesel (ULSD) fuel containing a maximum of 15 ppm sulfur, and new oil formulations to support the new technology. Cat® engines are designed to accommodate B20 biofuel. Your Cat dealer can provide more information regarding fuel and oil.

Broad Application Range
Industry-leading range of factory configurable ratings and options for agricultural, materials-handling, construction, mining, forestry, waste, and other industrial applications.

Package Size
Exceptional power density enables standardization across numerous applications. Available factory-installed configurations: full package, including radiator and Clean Emissions Module (CEM); package with CEM, but no radiator; and package with radiator installed, but CEM shipped loose.

Low-Cost Maintenance
Worldwide service delivers ease of maintenance and simplifies the servicing routine. Minimum 5000-hour diesel particulate filter (DPF) ash service interval enables low-cost maintenance. Capable of optimal oil change intervals of up to 500 hours, depending on rating, application, operating conditions, and maintenance practices. Engine is designed for a B10 life of up to 10,000 hours. The S•O•S℠ program is available from your Cat dealer to determine oil change intervals and provide optimal performance.

Quality
Every Cat engine is manufactured to stringent standards in order to assure customer satisfaction.

World-class Product Support Offered Through Global Cat Dealer Network
- Scheduled maintenance, including S•O•S℠ sample
- Customer Support Agreements (CSA)
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- Superior dealer service network
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Web Site: For additional information on all your power requirements, visit www.cat-industrial.com.

STANDARD ENGINE EQUIPMENT

Control System
Electronic control system, over-foam wiring harness, automatic altitude compensation, power compensated for fuel temperature, remote fan control, configurable software features, engine monitoring system SAE J1939 broadcast and control, integrated Electronic Control Unit (ECU)

Cooling System
Vertical outlet thermostat housing, centrifugal water pump, guidance on cooling system design available through your dealer to ensure equipment reliability

Exhaust System
Mid-mount turbocharged system with rear exhaust configuration

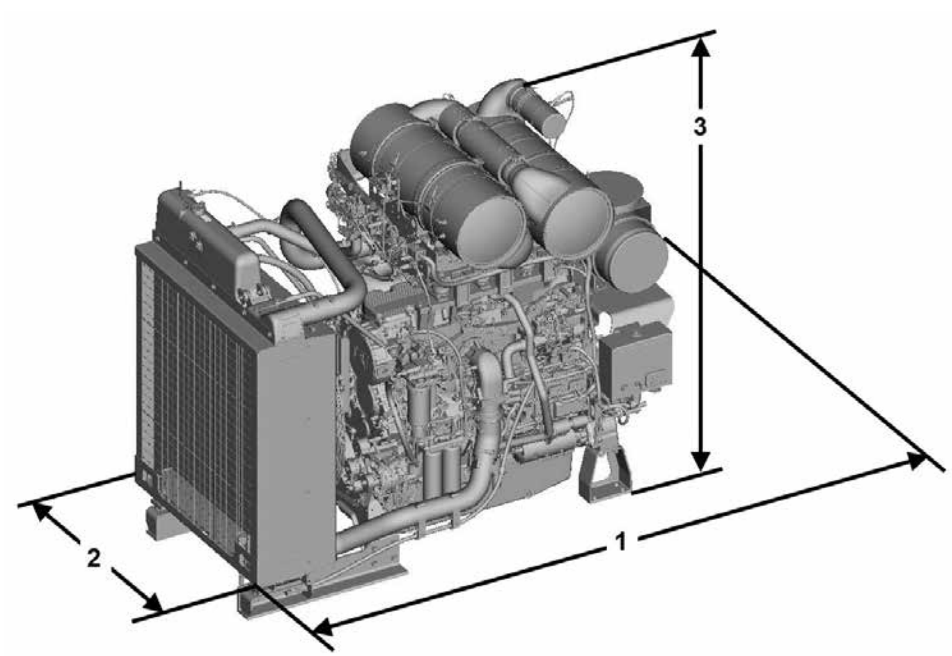
Flywheels and Flywheel Housing
SAE No. 0 and SAE No. 1 flywheel housings; available SAE 1 power take-off housing with optional SAE A, SAE B, and SAE C power take-off drives; engine power can also be taken from the front of the engine with optional attachments

Fuel System
MEUI injection; primary fuel filter, secondary fuel filters, fuel transfer pump, electronic fuel priming

Lube System
Open crankcase ventilation system with fumes disposal (optional OCV filter system); oil cooler, oil filler, oil filter, oil dipstick, oil pump (gear-driven); choice of sumps (front, rear, and center)

General
Paint: Cat yellow. Factory-fitted compressors are also available.

DIMENSIONS



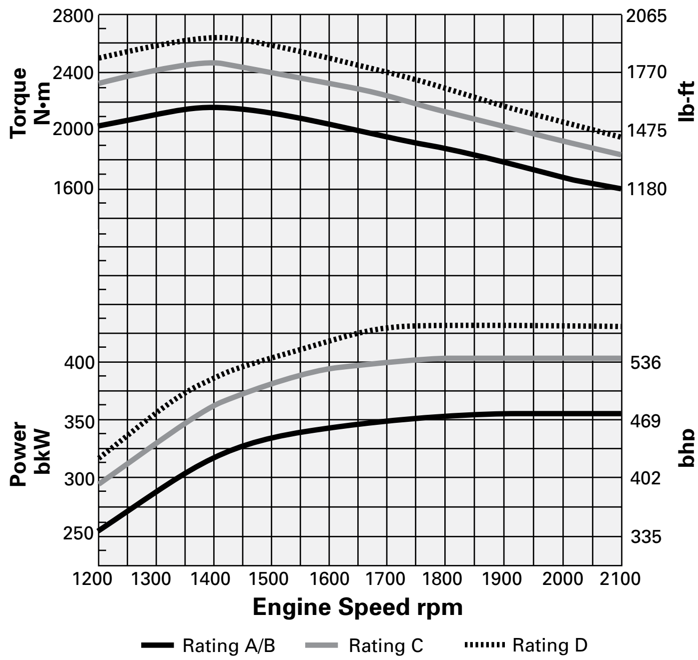
(1) Length — 2488 mm (98.0 in) (2) Width — 1229 mm (48.4 in) (3) Height — 2006 mm (79.0 in)

Note: Final dimensions dependent on selected options

PERFORMANCE DATA — PRELIMINARY

Turbocharged-Aftercooled — 1800-2100 rpm

Rated Speed



Speed Range

Rating	Aspiration	Rated Speed rpm	Rated Power bkW	Rated Power bhp	Speed rpm	Peak Torque N•m	Peak Torque lb-ft
A	TA	2100	354	475	1400	2174	1604
B	TA	2100	354	475	1400	2174	1604
C	TA	2100	403	540	1400	2472	1823
D	TA	2100	433	580	1400	2655	1958

RATING DEFINITIONS AND CONDITIONS

IND-A (Continuous) for heavy duty service where the engine is operated at maximum power and speed up to 100% of the time without interruption or load cycling.

IND-B for service where power and/or speed are cyclic (time at full load not to exceed 80%).

IND-C (Intermittent) is the horsepower and speed capability of the engine where maximum power and/or speed are cyclic (time at full load not to exceed 50%).

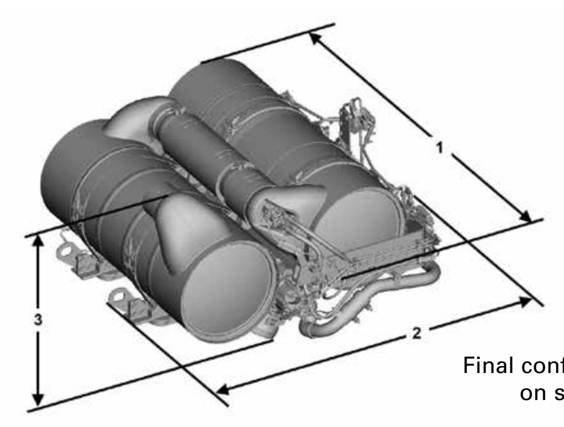
IND-D for service where maximum power is required for periodic overloads.

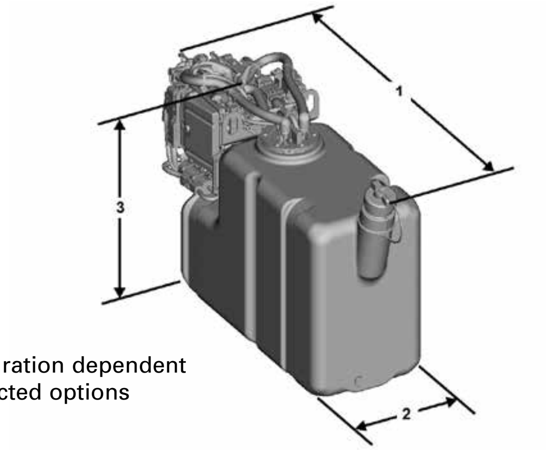
Rating Conditions are based on SAE J1995, inlet air standard conditions of 99 kPa (29.31 in Hg) dry barometer and 25°C (77°F) temperature. Performance measured using a standard fuel with fuel gravity of 35° API having a lower heating value of 42 780 kJ/kg (18,390 btu/lb) when used at 29°C (84.2°F) with a density of 838.9 g/L.

C15 ACERT™ Industrial Power Unit

Tier 4 Final, Stage IV Technology
354-433 bkW/475-580 bhp @ 1800-2100 rpm

AFTERTREATMENT CONFIGURATION





Final configuration dependent on selected options

IND-A & IND-B RATINGS
330.2 mm (13 in) DIAMETER
STANDARD CONFIGURATION SHOWN
Approximate Size and Weight
(1) Length — 1077 mm (42.4 in)
(2) Width — 1069 mm (42.1 in)
(3) Height — 654 mm (25.7 in)
Weight — 256 kg (564.4 lbs)

IND-C & IND-D RATINGS
355.6 mm (14 in) DIAMETER
STANDARD CONFIGURATION SHOWN
Approximate Size and Weight
(1) Length — 1153 mm (45.4 in)
(2) Width — 1112 mm (43.8 in)
(3) Height — 652 mm (25.7 in)
Weight — 268 kg (590.8 lbs)

MAXIMUM 48.4 L (51.1 U.S. qt)
PETU CONFIGURATION SHOWN
Approximate Size and Weight
(1) Length — 854 mm (33.6 in)
(2) Width — 287 mm (11.3 in)
(3) Height — 551 mm (21.7 in)
Weight, dry — 19.42 kg (42.8 lbs)

CEM Configuration
Standard configuration includes Diesel Particulate Filter (DPF), Diesel Oxidation Catalyst (DOC), Selective Catalytic Reduction (SCR), and supporting structure. Multiple mounting configuration options available for aftertreatment system.

PETU Configuration
Pump Electronic Tank Unit (PETU), consisting of Diesel Exhaust Fluid (DEF) tank with integrated Dosing Control Unit (DCU). Available in different volume configurations.

Contact your Cat dealer for additional information.

AFTERTREATMENT FEATURES

Regeneration: Cat Regeneration System maximizes fuel efficiency during regeneration. Transparent regeneration maximizes uptime.

Mounting: Industrial power units have standard horizontal mounting.

Service: Minimum 5000-hour diesel particulate filter ash service interval. PETU filter service is 5000 hours.

Available in 12V or 24V systems

STANDARD EMISSIONS CONTROL EQUIPMENT

Cat Regeneration System
CEM: Clean Emissions Module
DOC: Diesel Oxidation Catalyst
ECU: Aftertreatment Electronic Control Unit
DPF: Diesel Particulate Filter
NRS: NOx Reduction System
SCR: Selective Catalytic Reduction
PETU: Pump Electronic Tank Unit

Attachment C

US_Magnesium P-0 Pump Electric Conversion Cost Estimate

Description	Unit	Est. Quantity	Unit Cost	Item Cost
Low Head, high Volume Pump				
Centrifugal Pump, 5,000 gpm, 250 HP	EA	2	$ 51,000	$ 102,000
Pump Installation	EA	2	$ 10,000	$ 20,000
3-phase Electricity Power Line				
Electrical utility pole, wood pole yellow pine, penta-treated, 35', class 3	EA	78	$ 1,213	$ 95,100
Cross arms with hardware & insulators, 4' long	EA	78	$ 354	$ 27,800
Structural excavation for minor structures, bank measure, medium clay, pits to 6' deep, hand pits	B.C.Y	160	$ 150	$ 24,000
C.I.P. concrete forms, equipment foundations, 1 use	SFCA	1,362	$ 17	$ 23,300
Overhead ground wire	W.Mile	2	$ 8,467	$ 15,700
Non-metallic sheathed cable, copper with ground wire, 600 V, 3 conductor, #10, (Romex)	LF	9,800	$ 3	$ 32,700
Transformer				
Transformer, oil-filled, 5kV or 15kV, with taps, 277/480v secondary, 3 phase, 150kVA, pad mounted	EA	1	$ 13,939	$ 13,900
Transformer Installation	EA	1	$ 7,500	$ 7,500
Pad installation	EA	1	$ 2,500	$ 2,500
			Construction Subtotal [1]	$ 364,500
			Engineering and Administration (15%)	$ 51,675
			Construction Oversight and Project Management (15%)	$ 51,675
			Contingency (30%)	$ 103,350
			Total	$ 571,200

INSTRUCTIONS GEK-7588

GAS TURBINE POWER PLANT

VOLUME I

GAS TURBINE UNIT

12,700/15,250 KW

SIMPLE-CYCLE, SINGLE-SHAFT GAS TURBINE

TURBINE NOS. 214034, 214035, & 214036

furnished

NATIONAL LEAD COMPANY

MAGNESIUM DIVISION

ROWLEY, UTAH

GE REQUISITION NO. 480-68392

CUSTOMER ORDER NO. 5-4540-1-(I)-J11B

GAS TURBINE DEPARTMENT

GENERAL ELECTRIC

SCHENECTADY, N. Y.

Printed in U.S.A.

11/70-A.J.T.

GENERAL

This publication contains the general instructions and recommended procedures for operating and servicing a gas turbine and its auxiliary and driven equipment. One or more volumes may be utilized as required; the location of each type of data (regardless of which volume it appears in) being listed in the Table of Contents in this volume.

A series of illustrations has been provided following the Table of Contents. These illustrations show the gas turbine both assembled and in various stages of manufacture. Photographs of the units auxiliary equipment have also been included. The first illustration shows a simplified diagram of how a gas turbine works and is pertinent to the following discussion

PRINCIPLES OF GAS TURBINE OPERATION

The rotor (compressor/turbine) is initially brought to speed by a starting device (diesel, electric, or steam). Atmospheric air is then drawn into the compressor and raised to a static pressure several times that of the atmosphere. This high pressure air flows to combustion chambers where fuel is delivered under pressure and a high voltage spark ignites the fuel-air mixture. (once ignited, combustion will remain continuous in the air stream for as long as fuel is delivered to the combustion chamber). The products of combustion (high pressure, high temperature gases) expand thru the turbine and are exhausted to atmosphere or to a heat recovery device.

As the hot gases pass thru the turbine, they cause the turbine to spin; thus rotating the compressor and applying a torque output to the driven accessories and to the driven load. The rotor, on General Electric gas turbines, spins in a counterclockwise direction when viewed from the inlet end.

For additional data on gas turbines,auxiliary devices, and functional systems, refer to Tab 1 in this volume.

DESIGN DATA

Turbine Nos. 214034, 214035, + 214036

	*** Nameplate Rating		Maximum Capability*
	NEMA/BASE (Gas Fuel)	**SITE/BASE (Gas Fuel)	(Emergency Condition, Peak Load, Gas Fuel, 3" H_2O Inlet Loss and 3" H_2O Exhaust Back Pressure
Rating	15,250 KW	12,700 KW	18,850 KW
Altitude	1000 FT	4200 FT	4200 FT
Compressor			
Stages	16	16	16
Speed	5100 RPM	5100 RPM	5100 RPM
Inlet temperature	80°F	80°F	0°F
Inlet pressure	14.17 PSIA	12.51 PSIA	12.51 PSIA
Turbine			
Stages	2	2	2
Speed	5100 RPM	5100 RPM	5100 RPM
Exhaust temperature	930°F	940°F	1000°F
Exhaust pressure	14.17 PSIA	13.34 PSIA	12.74 PSIA

Performance Curves

401 HB 416	Base Load, on Gas and Oil Fuel, with 3" H_2O Back Pressure
401 HB 417	Base Load, on Gas and Oil Fuel, with 20" H_2O Back Pressure
401 HA 418	Ambient Effect Curve for Base Load Curves
401 HB 419	Peak Load, on Gas and Oil Fuel, with 3" H_2O Back Pressure
401 HB 420	Peak Load on Gas and Oil Fuel, with 20" H_2O Back Pressure
401 HA 421	Ambient Effect Curve for Peak Load Curves

(Continued)

DESIGN DATA

(Continued)

Fuel System - Natural Gas + Distillate Oil

Starting System - Diesel Engine
  Model - V8-300
  Rating - 300HP @ 3600RPM

Generator
  Model - ATl-HL-6
  Rating - 18,824KVA,1200RPM,13,800Volts,60Cycles and 0.85PF

Exciter
  Type - AR-6, Brushless
  Rating - 125 Volts

Control System
  Type - SPEEDTRONIC Control

Accessory Gear
  Type - A500-AG1BK
  Rating - 114HP
  Shaft Speed Ratio - 5100/3583/1884/1415 RPM

Main Load Gear
  Type - Western Fr. Size 4133HSB
  Shaft Speed Ratio-5107/1200RPM
  Nameplate Rating-18,824KW

Model List - 7L5A1GM10-1,-2, +

* Refer to Load Limit Section, uder General Operating Precautions in the OPERATION Section.

** Normal operating site conditions are 3" H_2O Inlet Duct Losses and 20" H_2O Exhaust Back Pressure and 4200 Ft. Elevation.

*** For ratings at other conditions, refer to the Performance Curves.

GENERAL ELECTRIC MODEL G5211, 13,300*KW GAS TURBINE

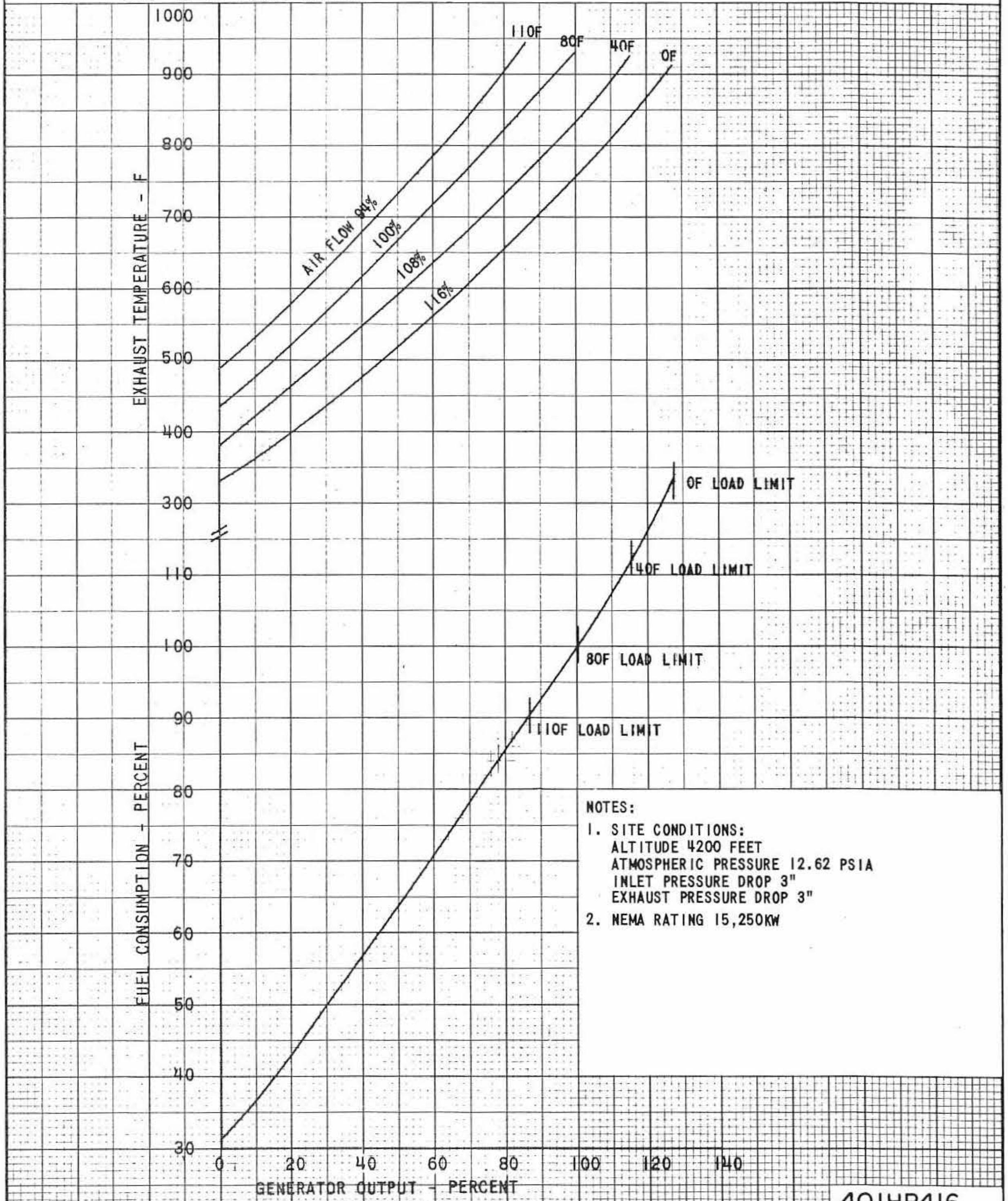
NATIONAL LEAD
MAGNESIUM PROJECT
DM 680

ESTIMATED PERFORMANCE

COMPRESSOR INLET TEMPERATURE 80 F
COMPRESSOR INLET PRESSURE 12.51 PSIA

FUEL		*NATURAL GAS	DISTILLATE OIL
DESIGN OUTPUT	KW	13,300	12,950
DESIGN HEAT RATE(LHV)	BTU/KW HR	14,400	14,610
DESIGN FUEL CONSUMPTION(LHV)	BTU/HR	191.6×10^6	189.2×10^6
RATIO HHV/LHV		1.11	1.06

DESIGN AIR FLOW 627,700 LB/HR
DESIGN SHAFT SPEED 5100 RPM
THIS IS A BASE RATING



NOTES:
1. SITE CONDITIONS:
   ALTITUDE 4200 FEET
   ATMOSPHERIC PRESSURE 12.62 PSIA
   INLET PRESSURE DROP 3"
   EXHAUST PRESSURE DROP 3"
2. NEMA RATING 15,250KW

GAS TURBINE DEPT.

401HB416

R. LATHERS MAY 1, 1969

GENERAL ELECTRIC MODEL G5211, 12,700*KW GAS TURBINE

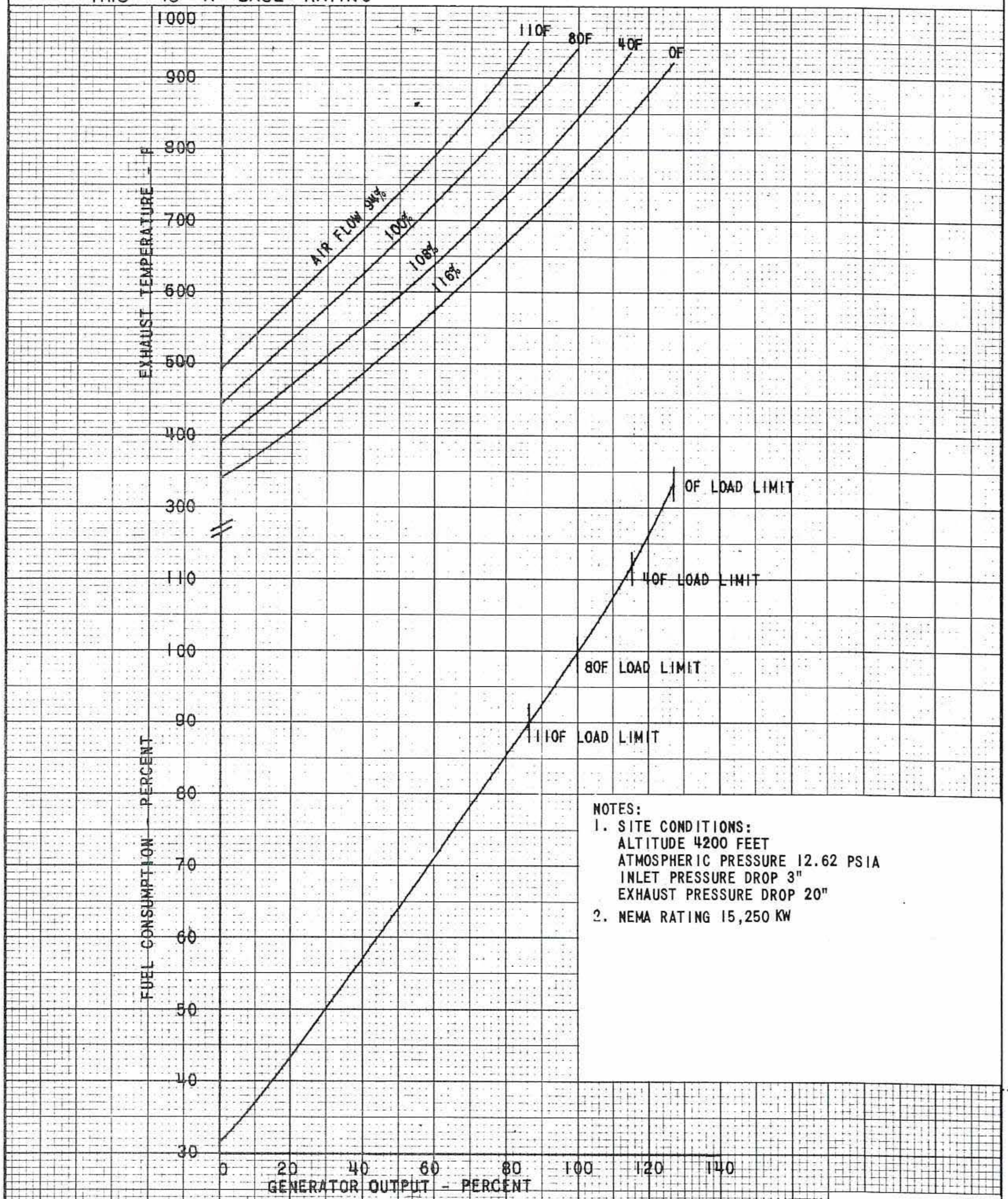
NATIONAL LEAD
MAGNESIUM PROJECT
DM 680

ESTIMATED PERFORMANCE

COMPRESSOR INLET TEMPERATURE 80 F
COMPRESSOR INLET PRESSURE 12.51 PSIA

FUEL			*NATURAL GAS	DISTILLATE OIL
DESIGN OUTPUT		KW	12,700	12,400
DESIGN HEAT RATE(LHV)		BTU/KW HR	15,010	15,220
DESIGN FUEL CONSUMPTION(LHV)		BTU/HR	190.6×10^6	188.8×10^6
RATIO HHV/LHV			1.11	1.06
DESIGN AIR FLOW	627,700	LB/HR		
DESIGN SHAFT SPEED	5100	RPM		

THIS IS A BASE RATING



NOTES:
1. SITE CONDITIONS:
   ALTITUDE 4200 FEET
   ATMOSPHERIC PRESSURE 12.62 PSIA
   INLET PRESSURE DROP 3"
   EXHAUST PRESSURE DROP 20"
2. NEMA RATING 15,250 KW

GAS TURBINE DEPT.

401HB417

R. LATHERS   MAY 1, 1969

EFFECT OF COMPRESSOR INLET TEMPERATURE ON
AIR FLOW, MAXIMUM OUTPUT, AND HEAT RATE

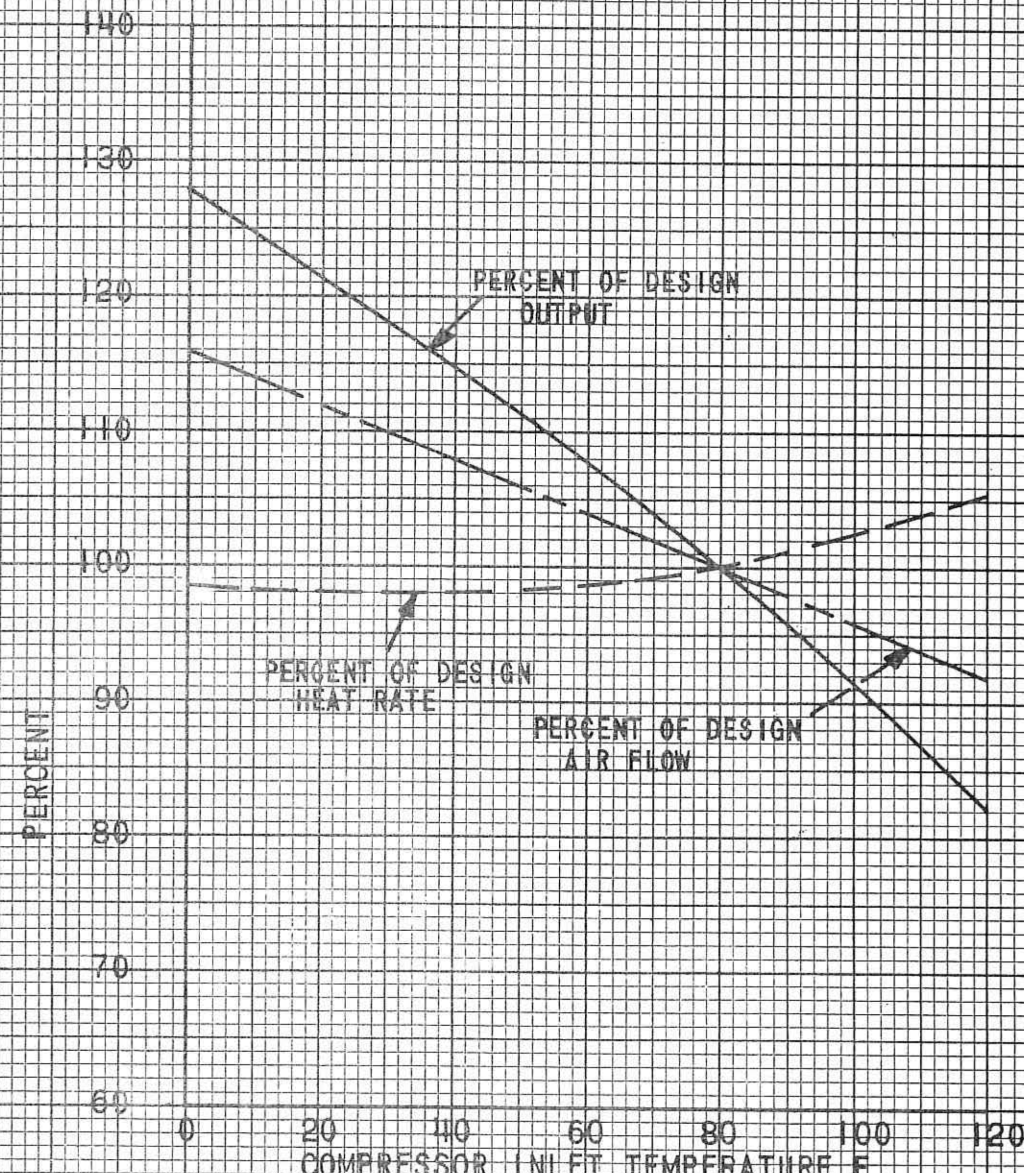
GENERAL ELECTRIC MODEL G5211

100% SPEED

NOTES: FOR DESIGN CONDITIONS AND NOTES
SEE PERFORMANCE CURVE 401HB416,
401HB417.

THIS IS A BASE RATING

NATIONAL LEAD
MAGNESIUM PROJECT
DM 630



GAS TURBINE DEPT.

401HA418

R. LATHERS

MAY 1, 1969

GENERAL ELECTRIC MODEL G5211, 15,150*KW GAS TURBINE

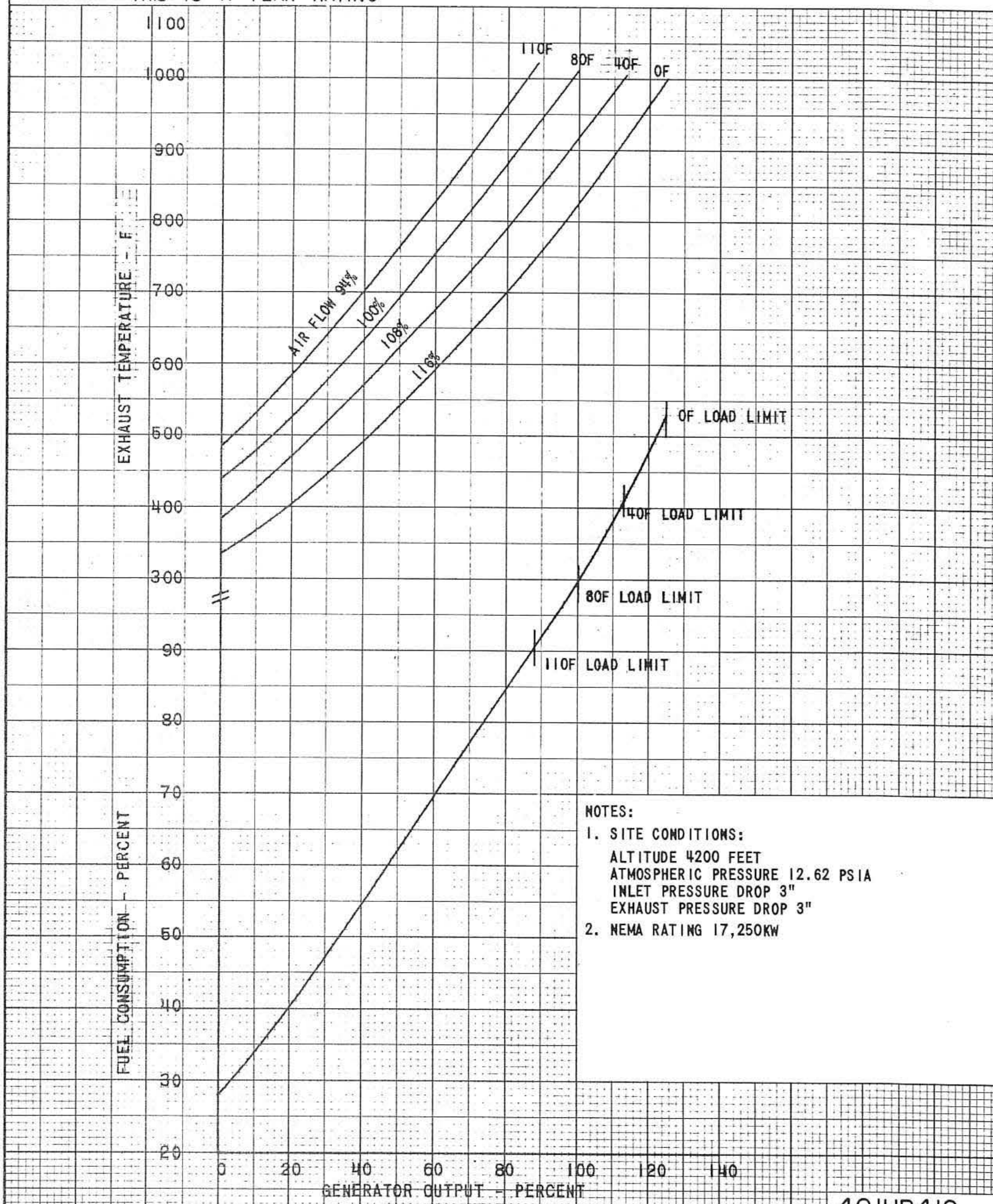
NATIONAL LEAD
MAGNESIUM PROJECT
DM 680

ESTIMATED PERFORMANCE

COMPRESSOR INLET TEMPERATURE 80 F
COMPRESSOR INLET PRESSURE 12.51 PSIA

FUEL		*NATURAL GAS	DISTILLATE OIL
DESIGN OUTPUT	KW	15,150	14,850
DESIGN HEAT RATE(LHV)	BTU/KW HR	14,070	14,220
DESIGN FUEL CONSUMPTION(LHV)	BTU/HR	213.1×10^6	211.1×10^6
RATIO HHV/LHV		1.11	1.06

DESIGN AIR FLOW 627,700 LB/HR
DESIGN SHAFT SPEED 5100 RPM
THIS IS A PEAK RATING



NOTES:
1. SITE CONDITIONS:
   ALTITUDE 4200 FEET
   ATMOSPHERIC PRESSURE 12.62 PSIA
   INLET PRESSURE DROP 3"
   EXHAUST PRESSURE DROP 3"
2. NEMA RATING 17,250KW

GAS TURBINE DEPT.

401HB419

R.LATHERS MAY 1,1969

GENERAL ELECTRIC MODEL G5211, 14,800*KW GAS TURBINE

NATIONAL LEAD
MAGNESIUM PROJECT
DM 680

ESTIMATED PERFORMANCE

COMPRESSOR INLET TEMPERATURE 80 F

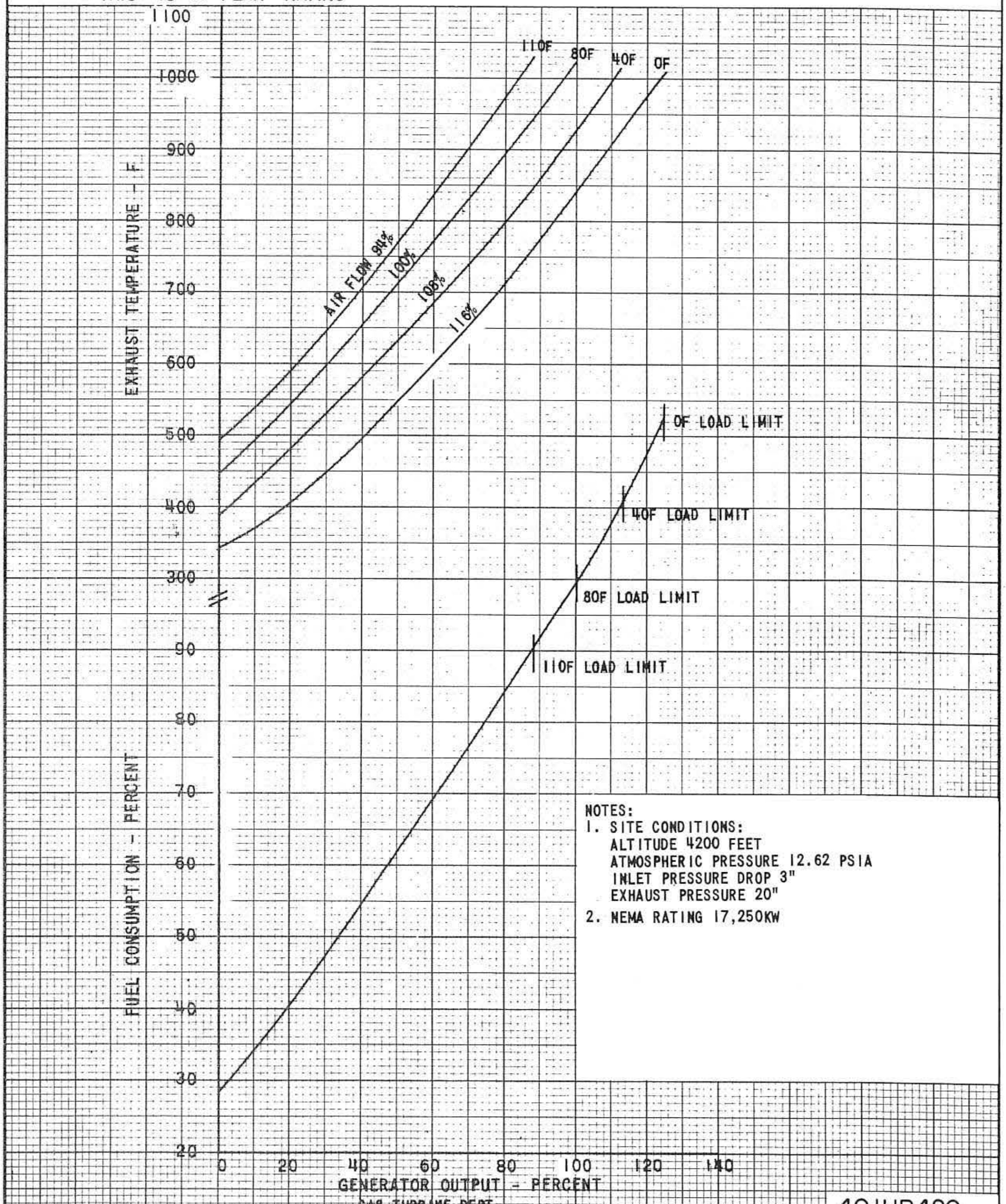
COMPRESSOR INLET PRESSURE 12.51 PSIA

FUEL		*NATURAL GAS	DISTILLATE OIL
DESIGN OUTPUT	KW	14,800	14,500
DESIGN HEAT RATE(LHV)	BTU/KW HR	14,360	14,520
DESIGN FUEL CONSUMPTION(LHV)	BTU/HR	212.6×10^6	210.5×10^6
RATIO HHV/LHV		1.11	1.06

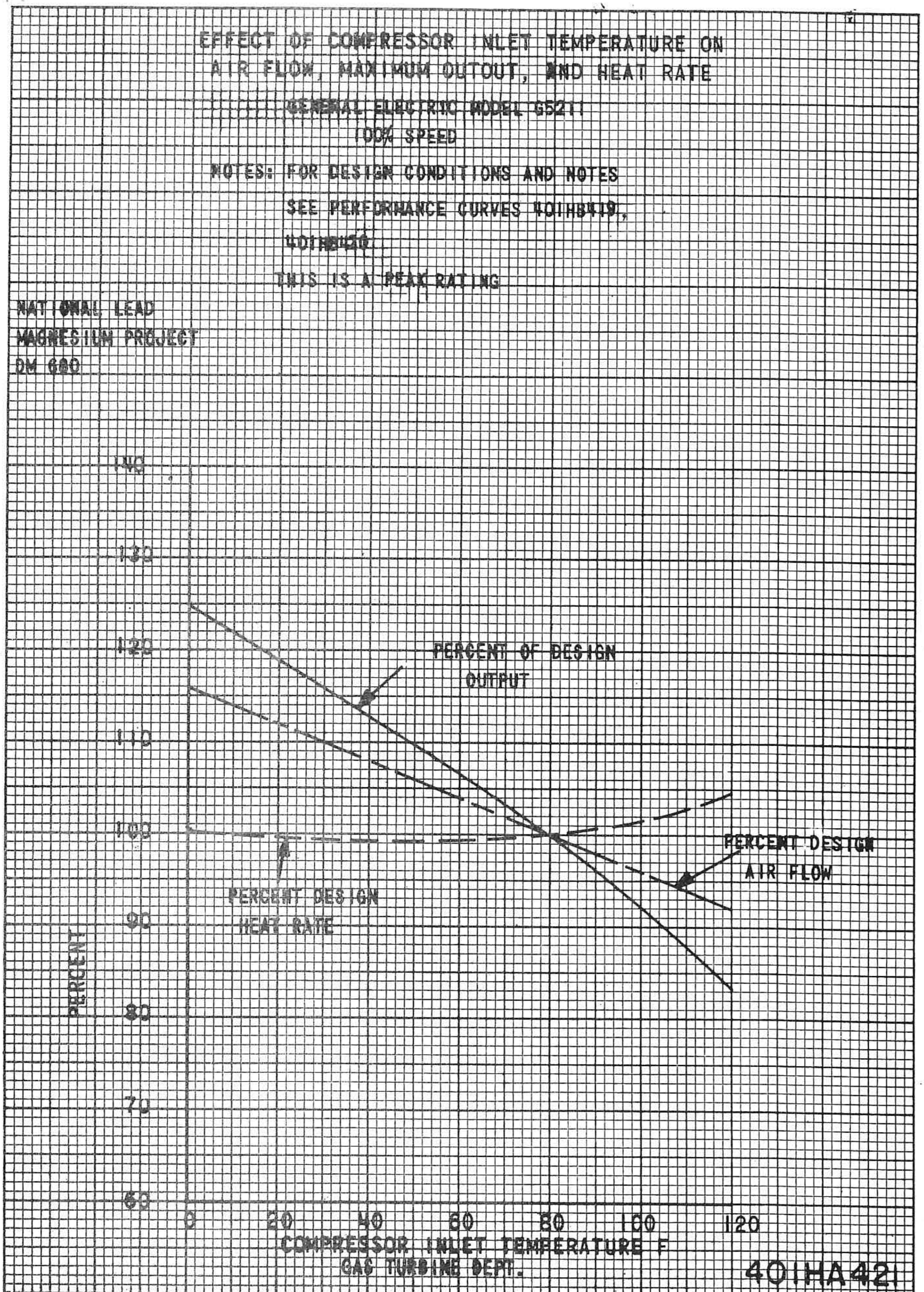
DESIGN AIR FLOW 627,700 LB/HR

DESIGN SHAFT SPEED 5100 RPM

THIS IS A PEAK RATING

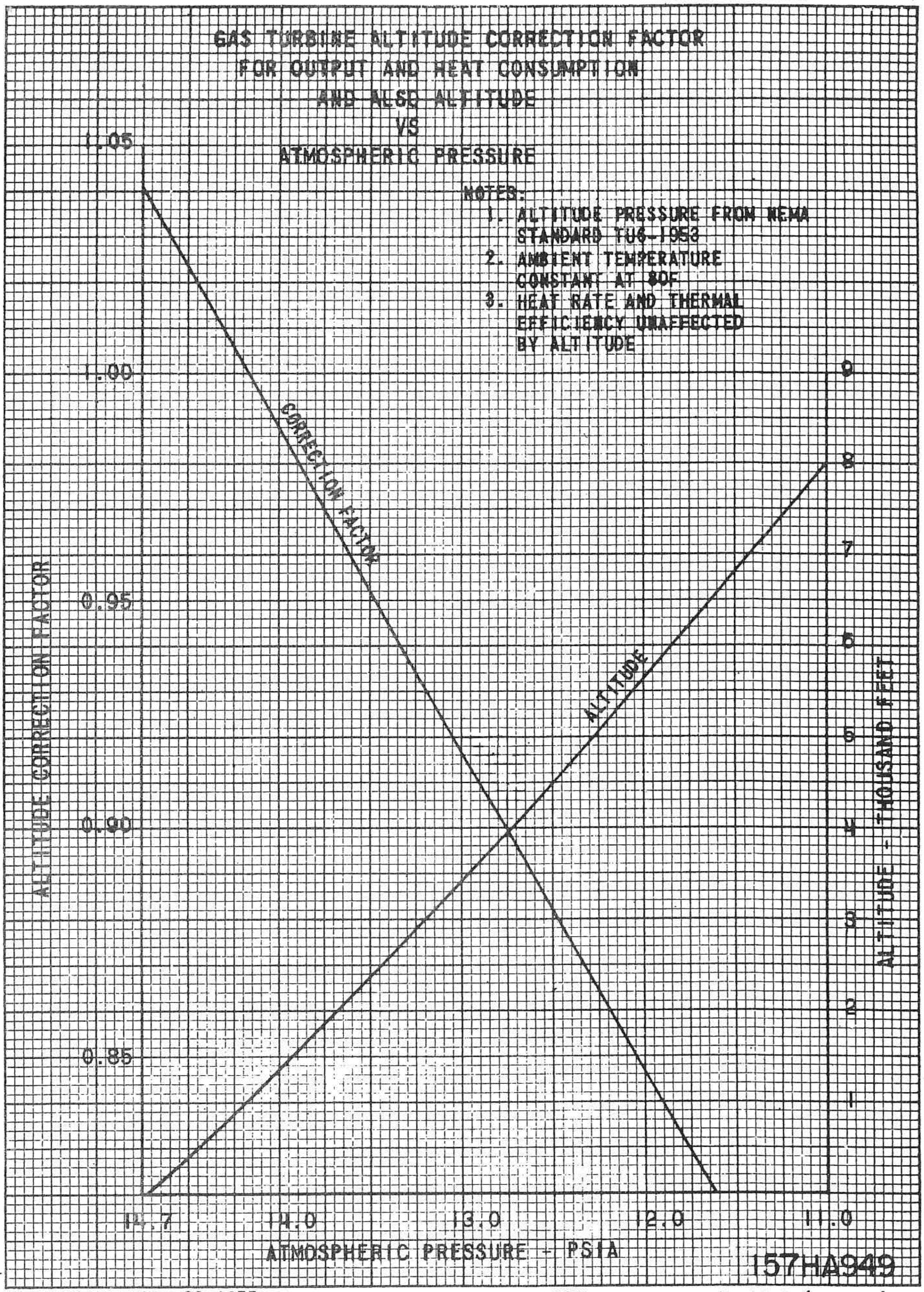


R.LATHERS MAY 1, 1969



R. LATHERS

MAY 1, 1969



K.D.KNAPP NOV. 23, 1955
REV.A OCT. 11, 1957
REV.B OCT. 29, 1959

REV. C NOV. 12, 1963 (M.J.P.)
REV. D JUN. 18, 1969 (K.D.K.)