SANTA ROSA *ENERGY* LLC

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September 4, 1998
Letter No. 2

Mr. A.A. Linero
Administrator, New Source Review Section
Division of Air Resources Management
State of Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road., MS# 5505
Tallahassee, FL 32399-2400

Subject: DEP File No. 1130003-005AC (PSD-FL-253)
Santa Rosa Energy Center

Dear Mr. Linero:

Santa Rosa Energy LLC is pleased to provide the following response to your letter dated August 3, 1998 in regards to the PSD application submitted on July 8, 1998.

Although the detailed design of the cogeneration facility is not complete, the steam turbine will be sized for approximately 74 MW. Under average annual conditions, the steam turbine will operate at approximately 53 MW. The turbine will be sized for 74 MW to handle any steam swings of the steam host (Sterling Fibers, Inc.) The Santa Rosa Energy Center will ensure that the steam turbine will not exceed 75 MW through both the design and operation of the steam turbine. The steam turbine specification will clearly state that the steam turbine's maximum rated capacity will not exceed 74.5 MW. Thus, the steam turbine will not be capable of exceeding 75 MW through its design by the steam turbine manufacturer. The second means of assurance will be through the control of the steam turbine's throttle valve. The distributed control system will be programmed to control the flow of steam to the steam turbine to limit the output of the steam turbine to less than 75 MW under all scenarios. This will have the effect of controlling the operation of the steam turbine to limit the output to less than 75 MW.

Many of the comments and questions in your letter concerned the use of steam injection for power augmentation. Following a more detailed review of the steam injection system and the associated operating requirements, Santa Rosa Energy LLC is modifying its preliminary design of the cogeneration facility to exclude the steam/water injection options on the combustion turbine. This will in effect lower the emissions inventory for the facility and will require modification of our permit application. Please find attached in Exhibit A the necessary documentation to modify our permit application.

The above explanations and modifications should provide sufficient assurance that the Santa Rosa Energy Center is not a power plant as defined in the Florida Electrical Power Plant Siting Act. The Santa Rosa Energy Center will have a steam turbine that will generate less than 75 MW through both its design and operation, and there will be no additional power generated through any other steam source, such as the combustion turbine utilizing steam or water injection.

The following are responses to your specific questions and comments:

1. *Power augmentation will allow the firing of additional natural gas while injecting water/steam into the turbine, to produce more megawatts. Explain the overall operation in the power augmentation mode. What technology is used to generate extra power (i.e., steam or water injection)? How much more power output is due to operation in the power augmentation mode. Provide an schematic of the power augmentation operation mode. What is the maximum manufacturer's recommended period (hr/year, hr/month) for operation in the power augmentation mode.*

   As stated above, Santa Rosa Energy LLC is modifying its design for the Santa Rosa Energy Center. The modified design does not include steam or water injection for the combustion turbine. Santa Rosa Energy LLC is also modifying its permit application to reflect the change in design. The attached Exhibit A includes the required documentation for this modification.

2. *Does Sterling Fibers Inc. have ownership on this project or simply a contract for steam? This information will allow us to determine if the facility requires a separate identification number in our database (ARMS system).*

As the project is currently planned, Sterling Fibers, Inc. will not have an equity position in the project. The site for the Santa Rosa Energy Center will be on land that will be leased from Sterling Fibers, Inc. The supply of steam from the cogeneration system to Sterling Fibers is through a contractual relationship.

3. *Submit General Electric performance data sheets for this turbine and the HRSG's manufacturer performance sheets.*

   Please find attached as Exhibit B the performance data sheets from GE for the combustion turbine and the emissions from Coen for the duct burner in the HRSG. The HRSG vendor has not been selected yet, therefore the final performance information is not available. Estimated HRSG performance from Nooter-Eriksen, an HRSG manufacturer, has been included in Exhibit B for reference.

4. *Expand on the details (G.E. papers, etc.) of the G.E Dry Low NOx burner technology and the Mark V control system.*

   Attached as Exhibit C is GE's technical papers for both the Dry Low Nox 2.6 Combustion System and the SPEEDTRONIC Mark V Gas Turbine Control System.

5. *Provide emission calculations under the normal operating scenario (excluding the power augmentation operation mode). What is the heat rate of this project (Btu/kwh)?*

   Emission calculations for the cogeneration facility operating without power augmentation are included in our modified permit application in Exhibit A. The heat rate for similar projects of this type are typically in the range of 6,800 to 7,000 Btu/kWh.

6. *What is the total megawatts generated from steam (only)? Is the total power output capacity of the cogeneration plant 241 MW?*

   With the elimitation of steam injection, the maximum power produced from steam is limited to approximately 74 MW, with an average annual output of approximately 53

MW. The maximum rated capacity of the cogeneration facility is 250.3 MW (net) with an annual average output of 216 MW (net). The 241 MW as stated in the permit application is a nominal rating based on the annual average combustion turbine performance (167 MW) and the gross output of the steam turbine (74 MW).

7. *The Department acknowledges your request for authorization in accordance with Rule 62.210.710 F.A.C., to allow for excess emissions beyond the regulatory limit during periods of startup/shutdown and power augmentation periods. As this is the case, submit specific details about the frequency of these periods. Attach manufacturer support data.*

The existing fleet of GE 7F combustion turbines consists of more than 67 units. Of these, approximately 36 units are used in base load operation, which is similar to the planned operation of the Santa Rosa Energy Center. The fleet average for base loaded GE 7F combustion turbines is approximately 12 start/shutdown cycles per year. We expect the Santa Rosa Energy Center to have a similar start/shutdown profile of approximately 12 start/shutdown cycles per year. These cycles will normally be a result of planned maintenance, forced outages, and combustion turbine trips.

The actual start-up time for a combined cycle cogeneration facility is dependent on the length of the shut-down period. Both GE and Westinghouse classify starts into hot, warm and cold starts, each with an associated start-up curve. The start-up curves for both GE and Westinghouse for a cold start range from 210 minutes to 230 minutes. These were the times used to base our request to exceed emission limits in the permit application. Included in Exhibit D are the start-up and shutdown curves for GE and Westinghouse for combined cycle facilities similar to the Santa Rosa Energy Center.

Additionally, we are providing a response to the United States Environmental Protection Agency's letter to Mr. Clair H. Fancy of FDEP. As discussed above, Santa Rosa Energy LLC is modifying its permit application to remove the use of power augmentation. This will result in an emissions inventory based on average annual conditions from the combustion turbine. Santa Rosa Energy LLC has included in Exhibit A the emissions inventory based on these conditions. Also, we have included in Exhibit A, a supplemental cost analysis for the BACT for an SCR with a controlled Nox rate of 3.5 ppmvd. The cost analysis for oxidation catalyst for VOC and CO emissions control also has been updated and included in Exhibit A. Santa Rosa Energy LLC still considers installation of an oxidation catalyst and an SCR to be not economically feasible for the Santa Rosa Energy Center. We request that EPA's comments be assessed in light of the change in project design and the additional information supplied in this submission.

We hope that the information provided herein is in sufficient detail for you to complete your analysis of our permit application. Santa Rosa Energy LLC is eager to move forward as quickly as possible on this project. Should you have any questions or require further information, please contact me at (847)559-9800 extension 325.

Sincerely,

SANTA ROSA ENERGY LLC

Craig Carson
Project Manager

CRC:rn

Enclosures : (upon request from air)

cc: Sylvia Alderman (Katz, Kutter)
Mike Cary (Weston)

File: SRO - ENV

cc: J. Heron, BAR
C. Holladay, BAR
EPA
NPS
NWD

EXHIBIT A

- Modified Emissions Inventory

  Revised Table 3-1 - Hourly Emissions Inventory

  Revised Table 3-2 - Annual Emissions Inventory

  Revised Tables B-1 and B-2 - Sample Calculations

- Modified Control Cost Analyses

  Revised Tables 5-1 and 5-2 - VOC Catalyst

  Revised Tables 5-3 and 5-4 - CO Catalyst

  Revised Tables 5-5 and 5-6 - SCR to 3.5 ppm

- Modified Modeling

  Revised Table 6-1 - Emission Rates and Stack Parameters

  Revised Table 6-8 - Results

Exhibit A - Discussion

Santa Rosa Energy LLC has revised the emissions inventory for the Santa Rosa Energy Center to reflect elimination of the power augmentation mode of operation during natural gas firing in the combustion turbine. Without power augmentation the worst case emissions while firing natural gas will occur at 100% load. Revised Tables 3-1 and 3-2, presenting hourly and annually emissions, respectively, are enclosed along with revised sample calculations (Tables B-1 and B-2).

The control cost estimates in Section 5 (Best Available Control Technology Analysis) of the application have been updated to reflect the revised emission inventory. In addition, the tables for SCR have been further revised for costs associated with attaining a 3.5 ppm NO_x concentration in the exhaust gas stream instead of 6.0 ppm. Attached are revised Tables 5-1 and 5-2 for VOC catalyst costs, Tables 5-3 and 5-4 for CO catalyst costs, and Tables 5-5 and 5-6 for SCR costs. The conclusions reached in the original application remain unchanged, i.e., installations of oxidation catalyst for CO and VOC emissions reductions and SCR for NO_x emissions reduction are not economically feasible.

The revised emissions have been modeled. Enclosed are revised Tables 6-1 and 6-8 presenting the emissions data and modeled results, respectively. The revised modeling shows ambient impacts are insignificant. A diskette providing the revised modeling inputs and outputs is enclosed.

TABLE 3-1 (revised 26 August 1998)
SANTA ROSA ENERGY CENTER
MAXIMUM HOURLY EMISSION RATES FROM THE COGENERATION SYSTEM
COMBUSTION TURBINE AND DUCT BURNER FIRING NATURAL GAS ONLY

POLLUTANT	COMBUSTION TURBINE EMISSIONS[a] (lb/hr)	DUCT BURNER EMISSIONS[b] (lb/hr)	TOTAL STACK EMISSIONS[c][d] (lb/hr)
Total Suspended Particulate[e]	9.5	4.7	14.2
Particulate Matter <10 microns[e]	9.5	4.7	14.2
Sulfur Dioxide	1.1	0.6	1.7
Nitrogen Oxides	64.1	46.8	110.9
Volatile Organic Compounds	2.9	11.1	14.0
Carbon Monoxide	31.5	46.8	78.3
Sulfuric Acid Mist[e]	Not Available	Not Available	Not Available
Lead[f]	Not Available	2.93E-04	2.93E-04
Beryllium[f]	Not Available	7.02E-06	7.02E-06
Mercury [f]	Not Available	1.52E-04	1.52E-04
Total Organic and Inorganic HAPs[f]	Not Available	1.10	1.10

[a] Emission rates for each pollutant are the highest short-term rates over the range of ambient air conditions and load levels for the combustion turbine as provided by the combustion turbine vendor. Refer to Table B-1.

[b] Based on full load conditions firing natural gas. Refer to Table B-1.

[c] Combustion turbine with duct burner will be exhausted through a single stack.

[d] Emissions from combustion turbine/duct burner systems operating simultaneously.

[e] Sulfuric acid mist emissions are not included with particulate matter emissions. There are not separate factors available for combustion turbines or duct burners firing natural gas.

[f] AP-42 emissions factors for HAPs are not available for natural gas firing for the combustion turbine thus HAPs were assumed to be insignificant. Natural gas emission factors for natural gas combustion in boilers were used for the duct burner because of the similarity (US EPA AP-42 5th ed, Supplement D, Section 1.4). Total HAPs includes the organic and inorganic species.

TABLE 3-2 (revised 26 August 1998)
SANTA ROSA ENERGY CENTER
MAXIMUM POTENTIAL ANNUAL EMISSIONS

POLLUTANT	COMBUSTION TURBINE WITH DUCT BURNER EMISSIONS[(a)(b)] (ton/yr)	PSD SIGNIFICANCE LEVEL[(c)] (ton/yr)
Total Suspended Particulate	54.7	25
Particulate Matter <10 microns	54.7	15
Sulfur Dioxide	6.4	40
Nitrogen Oxides	402.2	40
VOC	44.4	40
Carbon Monoxide	260.0	100
Sulfuric Acid Mist	Not Available	7
Lead [(b)]	8.20E-04	0.6
Beryllium [(b)]	1.97E-05	0.0004
Mercury [(b)]	4.26E-04	0.1
Total Organic and Inorganic HAPs [(b)]	3.10	-

[(a)] Based on hourly emissions for combustion turbine firing natural gas, i.e., at 100% load and an average annual ambient temperature of 68°F; duct burner at reduced annual average capacity firing natural gas; i.e., at 64% average annual capacity; and both operating at 8,760 hours per year. This scenario represents realistic operating conditions and provides operational flexibility.

[(b)] HAP emissions are presented for the duct burner only.

[(c)] From EPA PSD regulations, 40 CFR 52.21(b)(23)(j).

TABLE B-1 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER
POTENTIAL HOURLY EMISSION RATES FROM THE PROPOSED COGENERATION FACILITY

POLLUTANT NAME	EMISSION FACTOR (lb/MMBtu)	RATED HEAT INPUT (MMBtu/hr)	AMBIENT TEMP. (°F)	LOAD FACTOR (%)	POTENTIAL EMISSIONS (CONTROLLED)[a] (lb/hr)
COMBUSTION TURBINE					
Total Suspended Particulate	0.0051	1,847	40	100%	9.5
Particulate Matter <10 microns	0.0051	1,847	40	100%	9.5
Sulfur Dioxide	0.0006	1,847	40	100%	1.1
Nitrogen Oxides	0.0347	1,847	40	100%	64.1
Volatile Organic Compounds	0.0016	1,847	40	100%	2.9
Carbon Monoxide	0.0171	1,847	40	100%	31.5
Lead	N/D	1,847	40	100%	N/D
Sulfuric Acid Mist	N/D	1,847	40	100%	N/D
Beryllium	N/D	1,847	40	100%	N/D
DUCT BURNER					
Total Suspended Particulate	0.0080	585	(b)	100%	4.7
Particulate Matter <10 microns	0.0080	585	(b)	100%	4.7
Sulfur Dioxide	0.0010	585	(b)	100%	0.59
Nitrogen Oxides	0.0800	585	(b)	100%	46.8
Volatile Organic Compounds	0.0190	585	(b)	100%	11.1
Carbon Monoxide	0.0800	585	(b)	100%	46.8
Sulfuric Acid Mist	N/D	585	(b)	100%	N/D
Lead [c]	5.00E-07	585	(b)	100%	2.93E-04
Beryllium [c]	1.20E-08	585	(b)	100%	7.02E-06
Mercury [c]	2.60E-07	585	(b)	100%	1.52E-04
Total HAPs [c]	1.89E-03	585	(b)	100%	1.10

[a] Emission rates for each pollutant are the highest hourly rates over the range of ambient air conditions and load levels for the combustion turbines as provided by the combustion turbine vendor; for the duct burners, the hourly rate is based on operating at full capacity.

[b] Emission factors are not temperature dependent.

[c] Emission factors from US EPA AP-42, 5 th. ed. Supplement D. HHV or natural gas assumed to be 1,000 Btu/scf.
N/D indicates that emission factors are not available.

TABLE B-1 (revised 8/14/98) Continued
SANTA ROSA ENERGY CENTER
POTENTIAL HOURLY EMISSION RATES FROM THE PROPOSED COGENERATION FACILITY

HAP EMISSION FACTOR SUMMARY FOR THE DUCT BURNER

US EPA AP-42, 5 th ed, Supplement D Emission Factors (lb/10^6 scf nat gas)					
Organic Compounds			**Inorganic Compounds**		
Name of Gas Component	**Factor**	**(HAP yes/no)**	**Name of Gas Component**	**Factor**	**(HAP yes/no)**
2- Methylnaphthalene	2.40E-05	yes	Lead	0.0005	yes
2-Methylchloranthrene	1.80E-06	yes	Arsenic	2.00E-04	yes
7,12-Dimethylbenz(a)anthracene	1.60E-05	yes	Barium	4.40E-03	no
Acenaphthene	1.80E-06	yes	Beryllium	1.20E-05	yes
Acenphthracene	1.80E-06	yes	Cadmium	1.10E-03	yes
Anthracene	2.40E-06	yes	Chromium	1.40E-03	yes
Benz(a)anthracene	1.80E-06	yes	Cobalt	8.40E-05	yes
Benzene	2.10E-03	yes	Copper	8.50E-04	no
Benzo(a)pyrene	1.20E-06	yes	Manganese	3.80E-04	yes
Benzo(b)fluorthene	1.80E-06	yes	Mercury	2.60E-04	yes
Benzo(g,h,i)perylene	1.20E-06	yes	Molybdenum	1.10E-03	no
Benzo(k)fluoranthene	1.80E-06	yes	Nickel	2.10E-03	yes
Butane	2.10E+00	no	Selenium	2.40E-05	yes
Chrysene	1.80E-06	yes	Vanadium	2.30E-03	no
Dibenzo(a,h)anthracene	1.20E-06	yes	Zinc	2.90E-02	no
Dichlorobenzene	1.20E-03	yes	Total Inorganic Species	0.044	
Ethane	3.10E+00	no	Total non-HAPs	0.038	
Fluoranthene	3.00E-06	yes	Total Inorganic HAPs	0.0061	
Fluorene	2.80E-06	yes			
Formaldehyde	7.50E-02	yes	**SUMMARY**		
Hexane	1.80E+00	yes	**Total Species**	**11.33**	
Indeno(1,2,3-cd)pyrene	1.80E-06	yes	**Total non-HAPs**	**9.44**	
Naphthalene	6.10E-04	yes	**Total Inorganic HAPs**	**0.0061**	
Pentane	2.60E+00	no	**Total Volatile-HAPs**	**1.88**	
Phenanathrene	1.70E-05	yes	**Total HAPs**	**1.89**	
Propane	1.60E+00	no			
Pyrene	5.00E-06	yes			
Total Organic Species	11.28				
Total non-HAPs	9.40				
Total Volatile-HAPs	1.88				

TABLE B-2 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER
POTENTIAL ANNUAL EMISSION RATES FROM THE PROPOSED COGENERATION FACILITY
OPERATING AT 68 °F AMBIENT TEMPERATURE

POLLUTANT NAME	EMISSION FACTOR (lb/MMBtu)	EMISSION FACTOR BASIS	POTENTIAL EMISSIONS [(a)] (ton/yr)
COMBUSTION TURBINE			
Total Suspended Particulate	0.0054	(b)	41.6
Particulate Matter <10 microns	0.0054	(b)	41.6
Sulfur Dioxide	0.0006	(b)	4.8
Nitrogen Oxides	0.0349	(b)	271.0
Volatile Organic Compounds	0.0017	(b)	13.2
Carbon Monoxide	0.0166	(b)	128.8
Lead	N/D	N/D	N/D
Sulfuric Acid Mist	N/D	N/D	N/D
Beryllium	N/D	N/D	N/D
DUCT BURNER			
Total Suspended Particulate	0.0080	(c)	13.1
Particulate Matter <10 microns	0.0080	(c)	13.1
Sulfur Dioxide	0.0010	(c)	1.6
Nitrogen Oxides	0.0800	(c)	131.2
Volatile Organic Compounds	0.0190	(c)	31.2
Carbon Monoxide	0.0800	(c)	131.2
Sulfuric Acid Mist	N/D	N/D	N/D
Lead	5.00E-07	(e)	8.20E-04
Beryllium	1.20E-08	(e)	1.97E-05
Mercury	2.60E-07	(e)	4.26E-04
Total HAPs	1.89E-03	(e)	3.10

TABLE B-2 (CONTINUED)

(a) The following operating and design parameters were used in determining potential emissions from the combustion turbine and duct burner.

Combustion Turbine Parameters (Natural Gas):

Base load (%):	100%
Capacity factor(d):	100%
Inlet Air Temperature (°F):	68
Rated heat input (MMBtu/hr):	1,773
Annual hours of operation:	8,760

Duct Burners (Natural Gas Only):

Capacity factor(d):	64%
Rated heat input (MMBtu/hr):	585
Annual hours of operation:	8,760

(b) Emission factor provided by vendor performance data sheets for a combustion turbine operating at 68°F ambient temperature with a Dry Low NO_x combustor for natural gas firing.

(c) Emission factor provided by vendor for a duct burner equipped with a low NO_x burner.

(d) Factor to account for the percentage of time the unit will be in operation compared to the maximum heat input and 8,760 hours per year taking into account the variability of both heat input and hours of operation over a 12-month period.

(e) Emission factor from US EPA AP-42, 5 th. ed. Supplement D. Please see Table B-1 for emission factor summary.

N/D indicates that emission factors are not available.

SAMPLE CALCULATIONS

Emission Rates:

ton/yr = Emission factor [lb/MMBtu] x Heat input [MMBtu/hr] x Capacity factor (%) x Operating hours (hr/yr) / (2000 lb/ton)

For CO emissions from the combustion turbine during natural gas firing,

ton/yr = (0.0166 lb/MMBtu) x (1,772.8 MMBtu/hr) x (100%) x (8,760 hr/yr) / (2,000 lb/ton) = 129 ton CO/yr

TABLE 5-1 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
VOC CATALYST SYSTEM CAPITAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard VOC Catalyst System[b]	1.00 A	=	$	770,000
Instrumentation	0.10 A	=	$	77,000
Sales taxes	0.03 A	=	$	23,100
Freight	0.05 A	=	$	38,500
Purchased equipment cost, PEC	B = 1.18 A	=	$	908,600
Direct installation costs				
Foundations & supports	0.08 B	=	$	72,688
Handling & erection	0.14 B	=	$	127,204
Electrical	0.04 B	=	$	36,344
Piping	0.02 B	=	$	18,172
Insulation	0.01 B	=	$	9,086
Painting	0.01 B	=	$	9,086
Direct installation costs	0.30 B	=	$	272,580
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	1,181,180
Indirect Costs (installation)				
Engineering	0.10 B	=	$	90,860
Construction and field expenses	0.05 B	=	$	45,430
Contractor fees	0.10 B	=	$	90,860
Start-up	0.02 B	=	$	18,172
Performance test	0.01 B	=	$	9,086
Contingencies	0.03 B	=	$	27,258
Total Indirect Costs, IC	0.31 B	=	$	281,666
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	1,462,846

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 8 December 1997.

TABLE 5-2 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
VOC CATALYST SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS					COST
Direct Annual Cost, DC						
Replacement parts, catalyst (3 year life)						
Catalyst cost[a]	0.381 [b]x \$ 840,000	x	1.08			\$ 345,690
Spent catalyst removal cost	0.381 [b]x \$ 30,000					\$ 11,432
Total DC						\$ 357,122
Indirect Annual Costs, IC						
Administrative charges	2% of Total Capital Investment = 0.02 (\$1462846)					\$ 29,257
Property tax	1% of Total Capital Investment = 0.01 (\$1462846)					\$ 14,628
Insurance	1% of Total Capital Investment = 0.01 (\$1462846)					\$ 14,628
Capital recovery[c]	0.142 [1462846 - 30000 - 840000(1.08)]					\$ 74,840
Total IC						\$ 133,354
Performance Penalty [f]	164.9 kW	x	8,760 hr/yr	x \$ 0.04 /kW-hr[e]		\$ 57,781
Total Annual Cost						\$ 548,257

Uncontrolled VOC Emission Rate[d]	(lb/hr)	capacity factor	(hr/yr)	(ton/yr)
Combustion Turbine (natural gas):	2.9	100%	8,760	12.7
Duct Burner (natural gas):	11.1	64%	8,760	31.1
Total Uncontrolled VOC Emission Rate, ton/yr				43.8
Estimated VOC Control Efficiency[g], %				15%
Controlled VOC Emission Rate, ton/yr				37.2
Estimated tons of VOC Controlled, ton/yr				6.6
Annual Cost per Ton VOC Controlled, \$/ton				\$ 83,415

[a] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[b] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[c] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142

[d] Annual emissions assuming the combustion turbine operates at 100% load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[e] Average energy cost is \$0.04/kW-hr.

[f] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 164.9 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[g] 15% VOC average reduction expected for typical load conditions per vendor performance data sheet (0% - 30%).

TABLE 5-3 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
CO CATALYST SYSTEM CAPITAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard CO Catalyst System[b]	1.00 A	=	$	770,000
Instrumentation	0.10 A	=	$	77,000
Sales taxes	0.03 A	=	$	23,100
Freight	0.05 A	=	$	38,500
Purchased equipment cost, PEC	B = 1.18 A	=	$	908,600
Direct installation costs				
Foundations & supports	0.08 B	=	$	72,688
Handling & erection	0.14 B	=	$	127,204
Electrical	0.04 B	=	$	36,344
Piping	0.02 B	=	$	18,172
Insulation	0.01 B	=	$	9,086
Painting	0.01 B	=	$	9,086
Direct installation costs	0.30 B	=	$	272,580
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	1,181,180
Indirect Costs (installation)				
Engineering	0.10 B	=	$	90,860
Construction and field expenses	0.05 B	=	$	45,430
Contractor fees	0.10 B	=	$	90,860
Start-up	0.02 B	=	$	18,172
Performance test	0.01 B	=	$	9,086
Contingencies	0.03 B	=	$	27,258
Total Indirect Costs, IC	0.31 B	=	$	281,666
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	1,462,846

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 08 December 1997.

TABLE 5-4 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
CO CATALYST SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS				COST
Direct Annual Cost, DC					
Replacement parts, catalyst (3 year life)					
Catalyst cost[a]	0.381 [b]x $ 840,000	x	1.08		$ 345,690
Spent catalyst removal cost	0.381 [b]x $ 30,000				$ 11,432
Total DC					$ 357,122
Indirect Annual Costs, IC					
Administrative charges	2% of Total Capital Investment = 0.02 ($1462846)				$ 29,257
Property tax	1% of Total Capital Investment = 0.01 ($1462846)				$ 14,628
Insurance	1% of Total Capital Investment = 0.01 ($1462846)				$ 14,628
Capital recovery[c]	0.142 [1462846 - 30000 - 840000(1.08)]				$ 74,840
Total IC					$ 133,354
Performance Penalty[f]	164.9 kW	x	8,760 hr/yr	x $ 0.04 /kW-hr[e]	$ 57,781
Total Annual Cost					$ 548,257

Uncontrolled CO Emission Rate[d]	(lb/hr)	capacity factor	(hr/yr)		(ton/yr)
Combustion Turbine (natural gas):	29.4	100%	8,760		128.8
Duct Burner (natural gas):	46.8	64%	8,760		131.2
Total Uncontrolled CO Emission Rate, ton/yr					260.0
Estimated CO Control Efficiency[g], %					85%
Controlled CO Emission Rate, ton/yr					39.0
Estimated tons of CO Controlled, ton/yr					221.0
Annual Cost per Ton CO Controlled, $/ton				$	2,481

[a] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[b] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[c] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142

[d] Annual emissions assuming the combustion turbine operates at 100% load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[e] Average energy cost is $0.04/kW-hr.

[f] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 164.9 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[g] 85% CO average reduction expected for typical load conditions per vendor performance data sheet.

TABLE 5-5 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
SCR SYSTEM ANNUAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard SCR System[b]		=	$	1,500,000
Aqueous ammonia tank[c]		=	$	35,500
Equipment Cost	A	=	$	1,535,500
Instrumentation	0.10 A	=	$	153,550
Sales taxes	0.03 A	=	$	46,065
Freight	0.05 A	=	$	76,775
Purchased equipment cost, PEC	B = 1.18 A	=	$	1,811,890
Direct installation costs				
Foundations & supports	0.08 B	=	$	144,951
Handling & erection	0.14 B	=	$	253,665
Electrical	0.04 B	=	$	72,476
Piping	0.02 B	=	$	36,238
Insulation	0.01 B	=	$	18,119
Painting	0.01 B	=	$	18,119
Direct installation costs	0.30 B	=	$	543,567
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	2,355,457
Indirect Costs (installation)				
Engineering	0.10 B	=	$	181,189
Construction and field expenses	0.05 B	=	$	90,595
Contractor fees	0.10 B	=	$	181,189
Start-up	0.02 B	=	$	36,238
Performance test	0.01 B	=	$	18,119
Contingencies	0.03 B	=	$	54,357
Total Indirect Costs, IC	0.31 B	=	$	561,686
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	2,917,143

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 24 August 1998. Estimate does not include the aqueous ammonia tank.

[c] Estimated based on the size required for a 30-day supply for the combustion turbine system assuming 100% load at 68°F ambient temperature. Tank cost is estimated as $35,500 for a 22,000-gallon carbon-steel tank.

TABLE 5-6 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
SCR SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS	COST
Direct Annual Cost, DC		
Operating Labor		
Operator	0.5 hr/shift x 3 shift/day x 365 day/yr x $ 25 /hr	$ 13,688
Supervisor	15% of operator	$ 2,053
Operating Materials		
Aqueous ammonia (28%)[a]	221.8 lb NH_3/hr x 8,760 hr/yr x $ 0.130 /lb NH_3	$ 252,581
Maintenance		
Labor	0.5 hr/shift x 3 shift/day x 365 day/yr x $ 25 /hr	$ 13,688
Material	100% of maintenance labor	$ 13,688
Replacement parts, catalyst (3 year life)		
Catalyst cost[b]	0.381 [c] x $ 1,000,000 x 1.08	$ 411,536
Spent catalyst removal cost	0.381 [c] x $ 30,000	$ 11,432
Utility Costs		
Electricity for pump, fan, and heater[d]	129.2 kW x 8,760 hr/yr x $ 0.04 /kW-hr[e]	$ 45,274
Total DC		$ 763,938
Indirect Annual Costs, IC		
Overhead	60% of sum of operating, supv., & maint. labor, & maint. materials = 0.6(13687.5 + 2053.125 + 13687.5 + 13687.5)	$ 25,869
Administrative charges	2% of Total Capital Investment = 0.02 ($2917143)	$ 58,343
Property tax	1% of Total Capital Investment = 0.01 ($2917143)	$ 29,171
Insurance	1% of Total Capital Investment = 0.01 ($2917143)	$ 29,171
Capital recovery[f]	0.142 [2917143 - 30000 - 1000000(1.08)]	$ 257,296
Total IC		$ 399,852
Performance Penalty[g]	706.8 kW x 8,760 hr/yr x $ 0.04 /kW-hr[e]	$ 247,663
Total Annual Cost		$ 1,411,452

	(lb/hr)	capacity factor	(hr/yr)	(ton/yr)
Uncontrolled NOx Emission Rate[h]				
Combustion Turbine (natural gas):	62.0	100%	8,760	271.6
Duct Burner (natural gas):	46.8	64%	8,760	131.2
Total Uncontrolled NOx Emission Rate, ton/yr				402.7
Estimated NOx Control Efficiency[i], %				75%
Controlled NOx Emission Rate, ton/yr				99.9
Estimated tons of NOx Controlled, ton/yr				302.9
Annual Cost per Ton NOx Controlled, $/ton				$ 4,660

[a] Cost based on information from Chemical Market Reporter, February 9, 1998.

[b] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[c] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[d] Per Black & Veatch Publication, 2 kW per pound of contained ammonia are required for vaporizing aqueous ammonia, and 5 kW are required to run the pump and fan. 2 kW/lb x 0.28 lb NH_3/lb x 221.8 lb/hr + 5 kW/hr = 129.2 kW/hr.

[e] Average energy cost is $0.04/kW-hr.

[f] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142.

[g] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 706.8 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[h] Annual emissions assuming the combustion turbine operates at 100% load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[i] 75% NO_X reduction expected for typical load conditions per vendor performance data sheet.

TABLE 6-1
STACK CHARACTERISTICS USED TO IDENTIFY WORST-CASE LOAD CONDITIONS SANTA ROSA ENERGY CENTER, PACE, FLORIDA

STACK CHARACTERISTIC	NATURAL GAS FIRING		
	WINTER	AVERAGE	SUMMER
Height (m)	60.96	60.96	60.96
Inside Diameter (m)[a]	5.8	5.8	5.8
100% LOAD			
Exit Velocity (m/s)	18.3	17.6	16.9
Gas Exit Temperature (K)[b]	369.0	369.0	369.0
75% LOAD			
Exit Velocity (m/s)	14.7	14.3	13.8
Gas Exit Temperature (K)[b]	365.0	365.0	365.0
65% LOAD			
Exit Velocity (m/s)	13.6	13.3	12.9
Gas Exit Temperature (K)[b]	365.0	365.0	365.0
50% LOAD			
Exit Velocity (m/s)	12.1	11.8	11.5
Gas Exit Temperature (K)[b]	364.0	364.0	364.0

[a] Inside diameter represents diameter of a single flue.

[b] Exit temperature assumed to be equal for all seasonal conditions.

TABLE 6-8
ISCST3 MODELING RESULTS FOR
SANTA ROSA ENERGY CENTER PROPOSED COGENERATION PROJECT

POLLUTANT	TOTAL MAXIMUM EMISSIONS (lb/hr)	TOTAL MAXIMUM EMISSIONS (g/s)	MODELED MAXIMUM AMBIENT IMPACT FOR ALL RECEPTORS ($\mu g/m^3$) [a] AVERAGING PERIOD 1-HR	3-HR	8-HR	24-HR	ANNUAL
100% LOAD CONDITION							
Unity Modeled Concentration ($\mu g/m^3$)/(g/s)	-----	1.00	1.9677	0.6559	0.3279	0.1415	0.00746
Total Suspended Particulates	14.2	1.79				0.25	0.01
PM10	14.2	1.79				0.25	0.01
Sulfur Dioxide	1.7	0.21		0.14		0.03	0.002
Nitrogen Oxides [c]	136.1	17.15					0.13
Carbon Monoxide [c]	99.3	12.51	24.62		4.10		
50% LOAD CONDITION [b]							
Unity Modeled Concentration ($\mu g/m^3$)/(g/s)	-----	1.00	3.6658	1.4118	0.6482	0.3093	0.01203
Total Suspended Particulates	14.2	1.79				0.55	0.02
PM10	14.2	1.79				0.55	0.02
Sulfur Dioxide	1.7	0.21		0.30		0.07	0.003
Nitrogen Oxides [c]	87.8	11.06					0.13
Carbon Monoxide [c]	67.8	8.54	31.32		5.54		

NOTES

[a] - Maximum ISCST3 modeled concentration for five-year period 1985-1989, unless otherwise indicated.
[b] - 50% load assumed for turbine only. Duct burner emissions are for 100% load.
[c] - Emission rates for winter climate conditions, which are higher than for summer conditions, were used.

Exhibit B

Vendor Performance
and
Emission Data

POLSKY ENERGY CORPORATION
ESTIMATED PERFORMANCE - PG7241(FA)

LOAD CONDITION		BASE	75%	65%	50%
AMBIENT TEMP.	- Deg F.	68	68	68	68
AMBIENT RELATIVE HUMID	- %	60	60	60	60
OUTPUT	- kW	168300.	126200.	109400.	84200.
HEAT RATE (LHV)	- Btu/kWh	9460.	10250.	10900.	12330.
HEAT CONS. (LHV) X10-6	- Btu/h	1592.1	1293.5	1192.5	1038.2
EXHAUST FLOW X10-3	- lb/h	3507.0	2884.0	2685.0	2385.0
EXHAUST TEMP	- Deg F.	1122.	1147.	1164.	1192.
EXHAUST HEAT X10-6	- Btu/h	971.8	824.8	783.5	719.1
NOX	- ppmvd @ 15% O2	9.	9.	9.	9.
NOX AS NO2	- lb/h	59.	47.	43.	37.
CO	- ppmvd	9.	9.	9.	9.
CO	- lb/h	28.	23.	22.	19.
UHC	- ppmvw	7.	7.	7.	7.
UHC	- lb/h	14.	11.	11.	9.
SO2	- ppmvw	0.	0.	0.	0.
SO2	- lb/h	1.	1.	1.	1.
SO3	- ppmvw	0.	0.	0.	0.
SO3	- lb/h	0.	0.	0.	0.
SULFUR MIST	- lb/h	0.	0.	0.	0.
PART	- lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.				
ARGON	0.88	0.89	0.88	0.88
NITROGEN	73.94	74.20	74.24	74.31
OXYGEN	12.28	12.50	12.61	12.82
CARBON DIOXIDE	3.96	3.88	3.83	3.73
WATER	8.94	8.54	8.44	8.26

SITE CONDITIONS
****

ELEVATION	- ft.	60
SITE PRESSURE	- psia	14.67
INLET LOSS	- in. Water	4.5
EXHAUST LOSS	- in. Water	12
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20431
APPLICATION	-	7FH2 HYDROGEN-COOLED GENERATOR
COMBUSTION SYSTEM	-	9/42 DLN COMBUSTOR

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE
NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
THE FUEL HAS .2GRAINS/100SCF OF SULFUR.
THIS PERFORMANCE INCLUDES THE EFFECTS OF AN 85 % EFFECTIVE EVAPORATIVE COOLER.
THE COOLER IS TURNED ON FOR BASE LOAD ONLY.

IPS-70447 POLSKY7F version code-0597D-0597E-0597D-0 N
JBS 06-Nov-97 09:41 AM

Androscoggin /DB

COEN Company, Inc.
Leaders in Combustion Technology

1510 Rollins Road
Burlingame, CA 94010
Phone: (415) 697-0440
Fax: (415) 579-3255

from Burlingame Division

Date:	January 10, 1997	**No. of Pages:**	1
Company:	Polsky Energy Corporation	**From:**	Rick Fiorenza
Attention:	Mr. Bryan E. Schueler *Phone:* 847/559-9800 *Fax:* 847/559-1805	**Project:**	Androscoggin Energy Center (formely WEPCO 40D-11842-1)

Dear Bryan,

In response to your January 2, 1997 letter to Coen requesting us to review the current duct burner emissions levels for the proposed Androscoggin Energy Center project please note:

Coen is able to guarantee the duct burner emissions levels as stated below:

> Emissions are based upon the duct burner firing natural gas only (at maximum design capacity) and TEG conditions specified in your Jan. 2 letter.
>
> Burner Heat Release: 274 mmBTU/hr (net LHV)
> 304 mmBTU/hr (gross HHV)

NOx	0.080 lb/mmBTU	24.32 lb/hr
CO	0.080 lb/mmBTU	24.32 lb/hr
SO2	0.001 lb/mmBTU	0.30 lb/hr
VOC	0.019 lb/mmBTU	5.78 lb/hr
Part.	0.008 lb/mmBTU	2.43 lb/hr

* At lower firing rates the duct burner emission rates as stated in "lb/mmBTU" will vary; however during operation below capacity, the duct burner emissions will never exceed rates stated in "lb/hr" above.

In addition, Coen recommends a formal review of the entire system to optimize the operation for natural gas firing prior to commissioning the duct burners. We invision minor logic and equipment changes will be necessary and can be formally addressed at the appropriate time.

I hope the above information is helpful to your efforts as we look forward to working with you in the near future.

Sincerely,

Rick Fiorenza

Rick Fiorenza
Manager, Energy Systems

cc. Dave Noll, N/E
file: Document2

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NE NOOTER/ERIKSEN

PROPOSAL

Prop No. 809-03
September 3, 1998

Polsky Energy Corporation
850 Dundee Road, Suite 150
Northbrook, IL 60062

Attention: Joel Schroeder, Project Engineer (Fax # 847-559-1805)

Reference: Combined Cycle Project for Florida
One (1) GE Frame 7FA HRSG

ANY ACCEPTANCE OF THIS QUOTE SHALL CONSTITUTE AN ACCEPTANCE OF ALL THE TERMS AND CONDITIONS CONTAINED ON THE FRONT AND REVERSE SIDE OF THIS QUOTATION. PLEASE READ THEM CAREFULLY.

Gentlemen:

In reply to your RFQ e-mailed to us on September 2nd, 1998, for the above referenced project, we offer the following information for your review.

The budget price to design and supply one (1) fired, triple pressure level GE Frame 7FA HRSG is: ....

Estimated weight: .... 4,500,000 lbs.

Ex-works

This HRSG will be designed and fabricated in accordance with Section I of the ASME Boiler and Pressure Vessel Code.

The scope of supply of the HRSG is essentially complete from the combustion turbine outlet flange through the exhaust stack including all of the required pressure parts necessary to generate the desired steam production, natural gas only fired duct burner, interconnecting ASME Section I Code piping local to the boiler, boiler trim, ladders, platforms, and stairtower.

Options

1. The budget price add for freight to the nearest rail siding (for rail shipments) or plant gate (for truck shipments) is: ....

Performance Data

We have performed a preliminary heat balance to confirm that the HP, IP, and LP unfired steam performance requested in your RFQ can be met. The approximate unfired steam production is as follows:

- 510,000 pph of 1000°F HP Steam at 1450 psig
- 44,000 pph of 850°F IP Steam at 635 psig
- 57,000 pph of 400°F LP Steam at 75 psig
- 75,000 pph of 320°F Saturated Steam for Deaeration

We have assumed a "standard" static gas side pressure drop through the HRSG of 12" w.c. As the project evolves and more information becomes available, this and other data (i.e. expected steam production at part load CT operation, sliding pressure envelope, fired steam production demands, etc.) will need to be provided in order for us to provide a more definitive design and price.

Comments

1. The RFQ did not address silencing criteria. If available, please provide combustion turbine sound power levels and near field and far field noise requirements and we will review our offering to determine if noise attenuation devices are required.

2. A simple cycle bypass system was not requested and is not included in our price.

3. Per your request, our pricing includes a natural gas fired only duct burner. The performance information outlined above is based on the unfired steam production from the HRSG. Fired HP, IP and LP steam production demands will eventually need to be provided to us so we can design for the fired case.

Commercial

Progress payments keyed into major milestone dates will be required. Terms of payment are net thirty (30) days after invoice date.

Sales, use, gross receipts, excise, value added, and other taxes are not included and shall be paid direct to the proper taxing authorities by the purchaser or owner.

If the project is not near term it would be prudent to escalate our price .33% per month after December 31st, 1998 in order to cover increases in shop wages and raw material costs.

Due to the busy market conditions all of us in the power business are currently experiencing, drawing and document submittal lead times (i.e. General Arrangement Drawings, Foundation Loading Diagram, Foundation Base Plate Details, P&ID, etc.) are around fourteen to sixteen (14-16) weeks after receipt of an order and full release.

Again, due to the current market conditions, lead-time for equipment delivery is longer than it has been for several years. Based on current conditions, equipment deliveries can commence starting eleven to twelve (11-12) months after receipt of an order and complete three to four (3-4) months later. Please factor these lead times into your schedule for the project.

If you have any questions, please do not hesitate to contact Tony Hanlin (thermal design) or me.

Yours very truly,
Nooter\Eriksen, Inc.

Michael D. Grimm
Sales Engineer

cc: Tony Hanlin @ N/E
Power Technology Services

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Exhibit C

DLN 2.6 and Mark V Control

System Technical Information

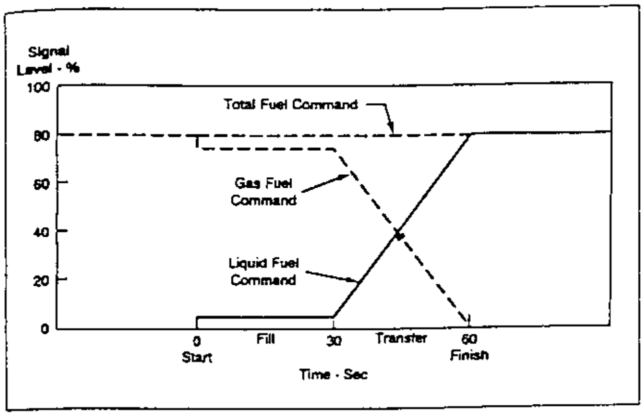

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Figure 3. Dual fuel transfer characteristics gas to liquid

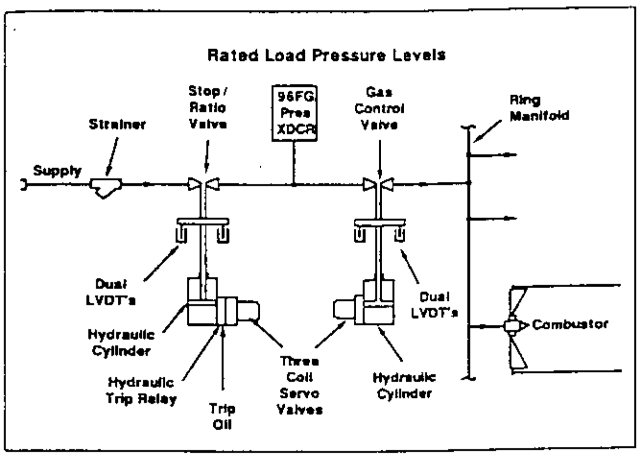

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Figure 4. Fuel gas control system

The liquid fuel control system is shown schematically in Fig. 5. Since the fuel pump is a positive displacement pump, the system achieves flow control by recirculating excess fuel from the discharge back to the pump suction. The required turn-down ratio is achieved by multiplying the fuel command by a signal proportional to turbine speed. The resultant signal positions the pump recirculation, or bypass valve, as appropriate to make the actual fuel flow, as measured by the speed of the liquid fuel flow divider, equal the product of turbine speed and fuel command. This approach assures a system in which both the liquid and gas fuel commands are essentially equal. Fuel distribution to the liquid fuel nozzles in the multiple combustors is achieved via the flow divider. This is a proven mechanical device which consists of carefully matched gear pumps for each combustor, all of which are mechanically connected to run at the same speed.

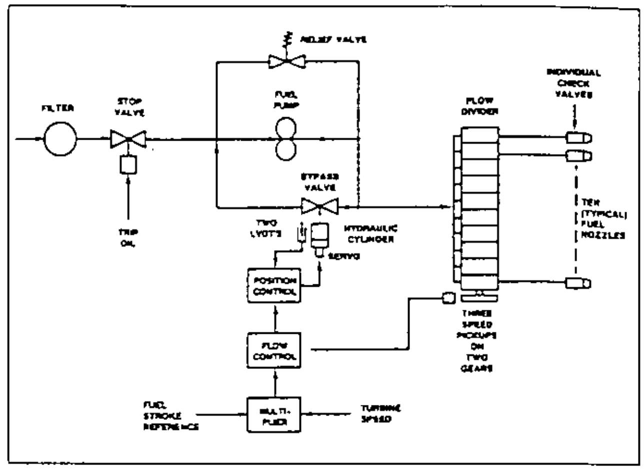

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Figure 5. Liquid fuel control system

Control of nitrogen oxide emissions may be accomplished by the injection of water or steam into the combustors. The amount of water required is a function of the fuel flow, the fuel type, the ambient humidity, and nitrogen oxide emissions levels required by the regulations in force at the turbine site. Steam flow requirements are generally about 40% higher than the equivalent water flow, but have a more beneficial effect on turbine performance. Accuracy of the flow measurement, control system, and system monitoring meets or exceeds both EPA and all local code requirements. An independent, fast-acting shutoff valve is provided to ensure against loss of flame due to over-watering on sudden load rejection.

Control of emissions utilizing dry low NO_x combustion techniques relies on multiple combustion staging to optimize fuel/air ratios and achieve thorough premixing in various combinations, depending on desired operating temperature. The emissions fuel control system regulates the division of fuel among the multiple-combustion stages according to a schedule which is determined by a calculated value of the combustion reference temperature. The control system also monitors actual combustion system operation to ensure compliance with the required schedule. Special provisions are incorporated to accommodate off-normal situations such as load rejection.

The gas turbine, like any internal combustion engine, is not self starting and requires an outside source of cranking power for start-up. This is usually a diesel engine or electric motor combined with a torque converter, but could also be a steam turbine or gas expander if external steam or gas supplies are available. Start-up via the generator, using variable frequency power supplies, is used on some of the larger gas turbines. Sufficient cranking power is provided to crank the unfired gas turbine at 25 to 30% speed, depending on the ambient temperature, even though ignition speed is 10 to 15%. This extra cranking power is used for gas path purging prior to ignition, for compressor water washing, and for accelerated cool-down.

A typical automatic starting sequence is shown in Fig. 6. After automatic system checks have been successfully completed and lube oil pressure established, the cranking device is started, and for diesel engines, allowed to warm up. Simple-cycle gas turbines with conventional upward exhausts do not require purging prior to ignition, and the ignition sequence can proceed as the rotor speed passes through firing speed. If ignition does not occur before the sixty second cross firing timer times out, the controls will automatically enter a purge sequence, as described later, and then attempt to refire.

However, if there is heat recovery equipment, or if the exhaust ducting has pockets where combustibles can collect, gas path purging is used to ensure a safe light-off. When the turbine reaches purge speed, this speed is held for the necessary purge period, usually sufficient to ensure three to five volume changes in the gas path. Purge times will vary from one minute to as long as ten minutes in some heat recovery applications. When purging is completed, the turbine rotor is allowed to decelerate to ignition speed. This speed has been found to be optimum from the standpoint of both thermal fatigue duty on the hot gas path components, as well as offering reliable ignition and cross firing of the combustors.

The ignition sequence consists of turning on ignition power to the spark plugs and then setting firing fuel flow. When flame is detected by the flame detectors, which are on the opposite side of the turbine from the spark plugs, ignition and cross firing are complete. Fuel is reduced to the warm-up value for one minute, and the starting device power is brought to maximum. If successful ignition and cross firing are not achieved within an appropriate period of time, the control system automatically reverts back to the purge sequence, and will attempt a second firing sequence without operator intervention. In the unlikely event of incomplete cross firing, it will be detected by the combustion monitor as a high exhaust temperature spread prior to loading the gas turbine.

After completion of the warm-up period, fuel flow is allowed to increase, and the gas turbine begins to accelerate faster. At a speed of about 30 to 50%, the gas turbine enters a predeter-

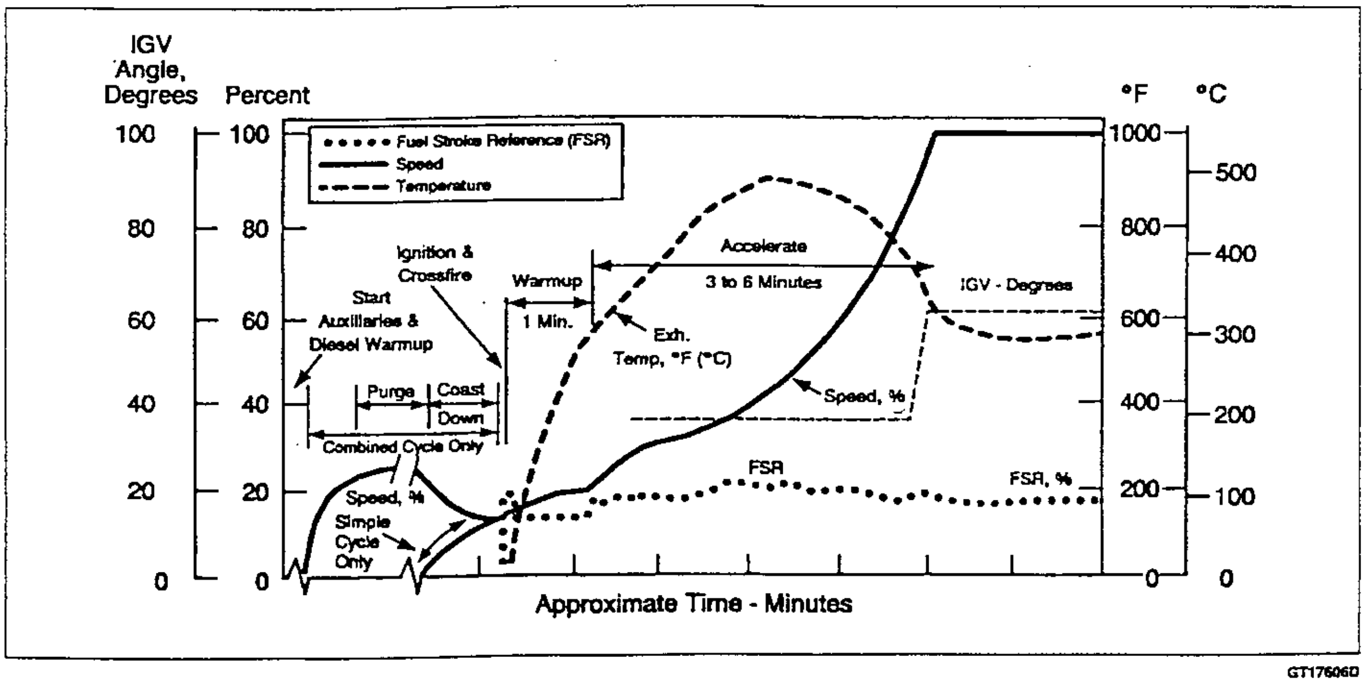

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Figure 6. Typical gas turbine starting characteristics

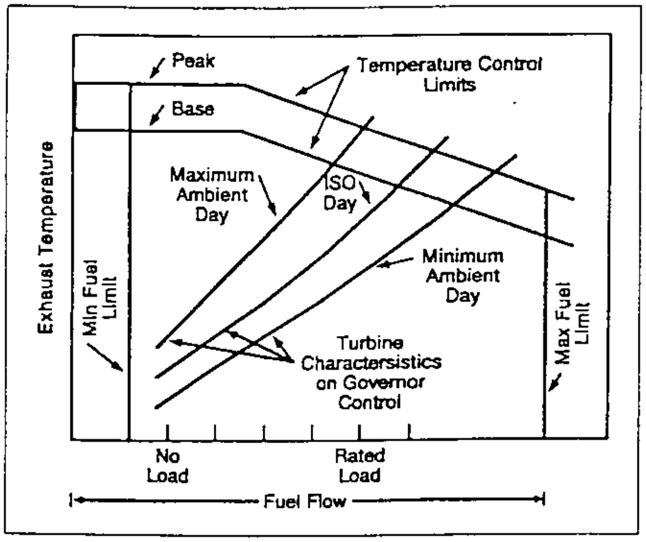

Figure 1. Gas turbine generator controls and limits

systems is shown in Fig. 2. The input to the system is the operator command for speed (when separated from the grid) or load (when connected). The outputs are the commands to the gas and liquid fuel control systems, the inlet guide vane positioning system and the emissions control system. A more detailed discussion of the control functionality required by the gas turbine may be found in Reference 1.

The fuel command signal is passed to the gas and liquid fuel systems via the fuel signal divider, in accordance with the operator's fuel selection. Start-up can be on either fuel, and transfers under load are accomplished by transitioning from one system to the other after an appropriate fill time to minimize load excursions. System characteristics during a transfer from gas to liquid fuel are illustrated in Fig. 3. Purging of the idle fuel system is automatic and continuously monitored to ensure proper operation. Transfer can be automatically initiated on loss of supply of the running fuel, which will be alarmed, and will proceed to completion without operator intervention. Return to the original fuel is manually initiated.

The gas fuel control system is shown schematically in Fig. 4. It is a two-stage system, incorporating a pressure control proportional to speed and a flow control proportional to fuel command. Two stages provide a stable turn-down ratio in excess of one-hundred-to-one, which is more than adequate for control under starting and warm-up conditions, as well as maximum flow for peak output at minimum ambient temperature. The stop/speed ratio valve also acts as an independent stop valve. It is equipped with an interposed, hydraulically-actuated trip relay which can trip the valve closed independent of control signals to the servo valve. Both the stop/ratio and control valves are hydraulically-actuated, single-acting valves that will fail to the closed position on loss of either signal or hydraulic pressure. Fuel distribution to the gas fuel nozzles in the multiple combustors is accomplished by a ring manifold in conjunction with careful control of fuel nozzle flow areas.

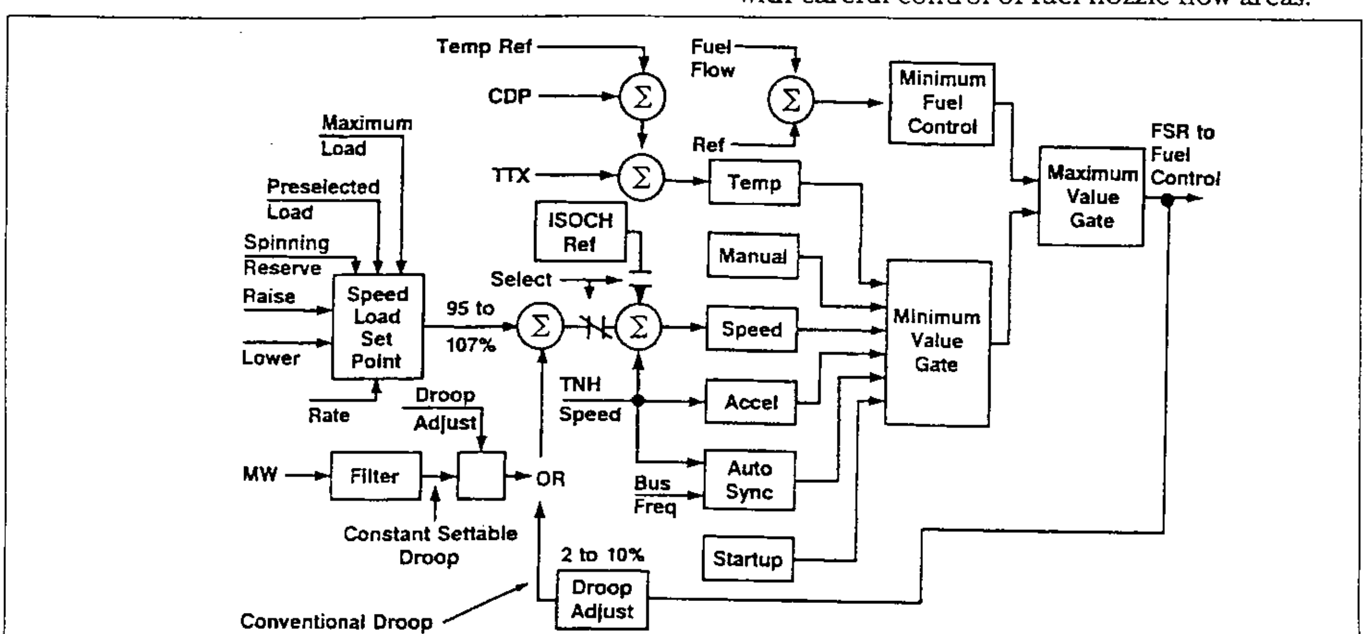

Figure 2. Gas turbine fuel control

Table 1
ADVANCES IN ELECTRONIC CONTROL CONCEPTS

System Type	Mark I	Mark II	Mark II ITS	Mark IV	Mark V
Introduced	1966	1973	1976	1982	1991
Total Shipped	850	1825	356	1080	530
Sequencing	Relays	Discrete Solid State Components		TMR Micro-processor	TMR Micro-processor
Control	Discrete Solid State	Inte-grated Circuits	I.C.s & Micro-processor	TMR Micro-processor	TMR Micro-processor
Protection	Relays	Relays & Solid State	I.C.s & Micro-processor	TMR Micro-processor	Independent TMR Micro-processor
Display	Analog Meters & Relay Annunciator	Analog and Digital Meters; Solid State Annunciator		CRT & LED Aux. Display	VGA Color Graphics
Input	Pushbuttons and Bat Handle Switches			Membrane Switches	Keyboard and/or CPD
Fault Tolerance	Manually Rejectable Failed Exhaust Thermocouples		Automatically Rejected Failed T.C.s	Hardware-based	SIFT

years of gas turbine control experience has involved more than 5,400 units, while the twenty-six years of electronic control experience has been centered on more than 4,400 turbine installations. Throughout this time period, the control philosophy shown in Table 2 has developed and matured to match the capabilities of the existing technology. This philosophy emphasizes safety of operation, reliability, flexibility, maintainability, and ease of use, in that order.

Table 2
GAS TURBINE CONTROL PHILOSOPHY

- SINGLE CONTROL FAILURE ALARMS WHEN RUNNING OR DURING START-UP
- PROTECTION BACKS UP CONTROL, THUS INDEPENDENT PROTECTIVE FAILURE WILL CAUSE SHUTDOWN
- TWO INDEPENDENT MEANS OF SHUTDOWN SHALL BE AVAILABLE
- DOUBLE FAILURE MAY CAUSE SHUTDOWN, BUT WILL ALWAYS RESULT IN SAFE SHUTDOWN
- GENERATOR DRIVE TURBINES WILL TOLERATE FULL LOAD REJECTION WITHOUT OVERSPEEDING
- CRITICAL SENSORS ARE REDUNDANT
- CONTROL IS REDUNDANT
- ALARM ANY CONTROL SYSTEM PROBLEMS
- STANDARDIZE HARDWARE AND SOFTWARE TO ENHANCE RELIABILITY WHILE MAINTAINING FLEXIBILITY

CONTROL SYSTEM FUNCTIONS

The SPEEDTRONIC™ Gas Turbine Control System performs many functions including fuel, air, and emissions control; sequencing of turbine fuel and auxiliaries for start-up, shutdown, and cool-down; synchronization and voltage matching of the generator and system; monitoring of all turbine, control and auxiliary functions; and protection against unsafe and adverse operating conditions. All of these functions are performed in an integrated manner which is tailored to achieve the previously described philosophy in the stated priority.

The speed and load control function acts to control the fuel flow under part-load conditions to satisfy the needs of the governor. Temperature control limits fuel flow to a maximum consistent with achieving rated firing temperatures, and controls air flow via the inlet guide vanes to optimize part-load heat rates on heat recovery applications. The operating limits of the fuel control are shown in Fig. 1. A block diagram of the fuel, air and emissions control panel and sensor faults. These faults are identified down to the board level for the panel and to the circuit level for the sensor or actuator components. The ability for on-line replacement of boards is built into the panel design, and is available for those turbine sensors where physical access and system isolation are feasible. Set points, tuning parameters, and control constants are adjustable during operation using a security password system to prevent unauthorized access. Minor modifications to sequencing and the addition of relatively simple algorithms can be accomplished when the turbine is not operating. They are also protected by a security password.

A printer is included in the control system and is connected via the operator interface. The printer is capable of copying any alpha-numeric display shown on the monitor. One of these displays is an operator configurable demand display that can be automatically printed at a selectable interval. It provides an easy means to obtain periodic and shift logs. The printer automatically logs time-tagged alarms, as well as the clearance of alarms. In addition, the printer will print the historical trip log that is frozen in memory in the unlikely event of a protective trip. The log assists in identifying the cause of a trip for trouble shooting purposes.

The statistical measures of reliability and availability for SPEEDTRONIC™ Mark V systems have quickly established the effectiveness of the new control because it builds on the highly successful SPEEDTRONIC™ Mark IV system. Improvements in the new design have been made in microprocessors, I/O capacity, SIFT technology, diagnostics, standardization, and operator information, along with continued application flexibility and careful design for maintainability. SPEEDTRONIC™ Mark V control is achieving greater reliability, faster mean-time-to repair, and improved control system availability than the SPEEDTRONIC™ Mark IV applications.

As of May 1994, almost 264 Mark V systems had entered commercial service, and system operation has exceeded 1.4 million hours. The established Mark V level of system reliability, including sensors and actuators, exceeds 99.9 percent, and the fleet mean-time-between-forced-outages (MTBFO), stands at 28,000 hours. As of May 1994, there were 424 gas turbine Mark V systems and 106 steam turbine Mark V systems shipped or on order.

CONTROL SYSTEM HISTORY

The gas turbine was introduced as an industrial and utility prime mover in the late 1940s, with initial applications in gas pipeline pumping and utility peaking. The early control systems were based on hydro-mechanical steam turbine governing practice, supplemented by a pneumatic temperature control, preset start-up fuel limiting, and essentially manual sequencing. Independent devices provided protection against overspeed, overtemperature, fire, loss of flame, loss of lube oil, and high vibration.

Through the early years of the industry, gas turbine control designs benefited from the rapid growth in the field of control technology. The hydro-mechanical design culminated in the "Fuel Regulator" and automatic relay sequencing for automatic start-up, shutdown, and cooldown, where appropriate for unattended installations. The automatic relay sequencing, in combination with rudimentary annunciator monitoring, also allowed interfacing with SCADA (Supervisory Control And Data Acquisition) systems for true continuous remote control operation.

This was the basis for introduction of the first electronic gas turbine control in 1968. This system, ultimately known as the SPEEDTRONIC™ Mark I Control, replaced the fuel regulator, pneumatic temperature control, and electromechanical starting fuel control with an electronic equivalent. The automatic relay sequencing was retained, and the independent protective functions were upgraded with electronic equivalents where appropriate. Because of its electrically dependent nature, emphasis was placed on integrity of the power supply system, leading to a DC - based system with AC - and shaft-powered backups. These early electronic systems provided an order of magnitude increase in running reliability and maintainability.

Once the change-over to electronics was achieved, the rapid advances in electronic system technology resulted in similar advances in gas turbine control technology, which is illustrated in Table 1. It should be noted that over forty

SPEEDTRONIC™ MARK V GAS TURBINE CONTROL SYSTEM

W.I. Rowen
GE Industrial & Power Systems
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OVERVIEW

The SPEEDTRONIC™ Mark V Gas Turbine Control System is the latest derivative in the highly successful SPEEDTRONIC™ series. Preceding systems were based on automated turbine control, protection, and sequencing techniques dating back to the late 1940s, and have grown and developed with the available technology. Implementation of electronic turbine control, protection, and sequencing originated with the Mark I system in 1968. The Mark V system is a digital implementation of the turbine automation techniques learned and refined in more than 40 years of successful experience, over 80% of which has been through the use of electronic control technology.

The SPEEDTRONIC™ Mark V Gas Turbine Control System employs current state-of-the-art technology, including triple redundant sixteen-bit microprocessor controllers, two-out-of-three voting redundancy on critical control and protection parameters, and Software Implemented Fault Tolerance (SIFT). Critical control and protection sensors are triple redundant and voted by all three control processors. System output signals are voted at the contact level for critical solenoids, at the logic level for the remaining contact outputs, and at three coil servo valves for analog control signals, thus maximizing both protective and running reliability. An independent protective module provides triple redundant hard-wired detection and shutdown on overspeed along with detecting flame. This module also synchronizes the turbine generator to the power system. Synchronization is backed up by a check function in the three control processors.

The Mark V Control System is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. In addition, inlet guide vanes and water or steam injection are controlled to meet emissions and operating requirements. If emissions control utilizes dry low NO_x techniques, fuel staging and combustion mode are controlled by the Mark V system, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V Control System. Turbine protection against adverse operating situations and annunciation of abnormal conditions are incorporated into the basic system.

The operator interface consists of a color graphic monitor and keyboard to provide feedback regarding current operating conditions. Input commands from the operator are entered using a cursor positioning device. An arm/execute sequence is used to prevent inadvertent turbine operation. Communication between the operator interface and the turbine control is through the Common Data Processor, or <C>, to the three control processors called <R>, <S>, and <T>. The operator interface also handles communication functions with remote and external devices. An optional arrangement, using a redundant operator interface, is available for those applications where integrity of the external data link is considered essential to continued plant operations. SIFT technology protects against module failure and propagation of data errors. A panel mounted back-up operator display, directly connected to the control processors, is provided to allow continued gas turbine operation in the unlikely event of a failure of the primary operator interface or the <C> module.

Built-in diagnostics for trouble-shooting purposes are extensive, and include "power-up", background and manually initiated diagnostic routines capable of identifying both control

GER-3658D

GE Power Generation

SPEEDTRONIC™ Mark V Gas Turbine Control System

W.I. Rowen
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6.1.1.7 Flame Detection

Reliable detection of the flame location in the DLN-2.6 system is critical to the control of the combustion process and to the protection of the gas turbine hardware. Four flame detectors in separate combustion chambers around the gas turbine are mounted to detect flame in all modes of operation. The signals from these flame detectors are processed in control logic and used for various control and protection functions.

6.1.1.8 Ignition System

Two spark plugs located in different combustion chambers are used to ignite fuel flow. These spark plugs are energized to ignite fuel during start-up only, at firing speed. Flame is propagated to those combustion chambers without spark plugs through crossfire tubes that connect adjacent combustion chambers around the gas turbine.

6.1.1.5 DLN-2.6 Inlet Guide Vane Operation

The DLN-2.6 combustor emission performance is sensitive to changes in fuel to air ratio. The combustor was designed according to the airflow regulation scheme used with inlet guide vane, (IGV), temperature control. Optimal combustor operation is crucially dependent upon proper operation along the predetermined temperature control scheme. Controlled fuel scheduling will be dependent upon the state of IGV temperature control. IGV temperature control on can also be referred to as combined cycle operation while IGV temperature control off is referred to as simple cycle operation.

6.1.1.6 DLN-2.6 Inlet Bleed Heat

Operation of the gas turbine with reduced minimum IGV settings can be used to extend the Premix operating region. Reducing the minimum IGV angle allows the combustor to operate at a firing temperature high enough to achieve optimal emissions.

Inlet bleed heating, (IBH), through the use of recirculated compressor discharge airflow, is necessary when operating with reduced IGV angles. Inlet heating protects the compressor from stall by relieving the discharge pressure and by increasing the inlet air stream temperature. Other benefits include anti-icing protection due to increased pressure drop across the IGV's.

The inlet bleed heat system regulates compressor discharge bleed flow through a control valve and into a manifold located in the compressor inlet air stream. The control valve varies the inlet heating air flow as a function of IGV angle. At minimum IGV angles the inlet bleed flow is controlled to a maximum of 5.0% of the total compressor discharge flow. As the IGV's are opened at higher loads, the inlet bleed flow will proportionally decrease until shut off.

The IBH control valve is monitored for its ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to warn the operator. If the condition persist for an additional amount of time, the inlet bleed heat system will be tripped and the IGV's minimum reference will be raised to the default value.

The IBH system monitors the temperature rise in the compressor inlet airflow. This temperature rise serves as an indication of bleed flow. Failure to detect a sufficient temperature rise in a set amount of time will cause the inlet bleed heat system to be tripped and an alarm annunciated.

The fuel flow to the six fuel nozzles and quaternary pegs are controlled by four independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one, (PM1), gas control valve two (PM2), gas control valve three, (PM3), and gas control valve four, (Quat).

The stop/ratio valve (SRV) is designed to maintain a predetermined pressure, (P2), at the inlet of the gas control valves. Gas control valves one through four, (GCV1-4), regulate the desired gas fuel flow delivered to the turbine in response to the command signal FSR, (Fuel Stroke Reference), from the SPEEDTRONIC panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. This flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software.

6.1.1.3 Gas Fuel Operation

The DLN 2.6 fuel system operation is fully automated, sequencing the combustion system through a number of staging modes prior to reaching full load. The primary controlling parameter for fuel staging is the calculated combustion reference temperature (TTRF1).Other DLN 2.6 operation influencing parameters available to the operator are the selection of IGV temperature control "on" or "off", and the selection of inlet bleed heat "on" or "off". To achieve maximum exhaust temperature as well as an expanded load range for optimal emission, IGV temperature control should be selected "ON", and inlet bleed heat should be selected "ON". Temperature control and Inlet bleed heat operation will be discussed later in this document.

6.1.1.4 Chamber arrangement

The 7F gas turbine employs 14 combustors. There are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent combustors. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi-nozzle cap assembly, liner assembly, and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion can, porting fuel to casing injection pegs located radially around the casing.

6.1.1 Dry Low Nox 2.6 Combustion System

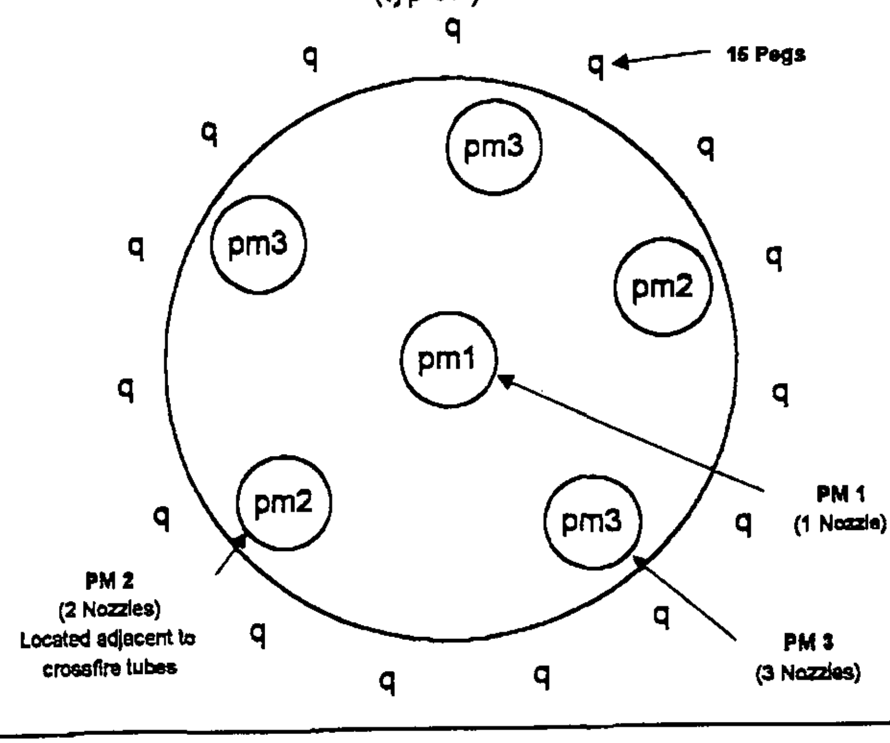
6.1.1.1 General

The dry low NOx 2.6 (DLN-2.6) conbustion system regulates the distribution of fuel delivered to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion chamber fuel nozzle assembly is calculated to maintain unit load and fuel split for optimal turbine emissions.

6.1.1.2 Gas Fuel System

The DLN 2.6 Combustion system consists of six fuel nozzles per combustion can, each operating as a fully premixed combustor, five located radially, one located in the center. The center nozzle, identified as PM1, (PreMix 1), two outer nozzles located adjacent to the crossfire tubes, identified as PM2, (PreMix 2), and the remaining three outer nozzles, identified as PM3, (PreMix 3). Another fuel passage, located in the airflow upstream of the premix nozzles, circumferentially around the combustion can, is identified as the quaternary fuel pegs, (see following illustration.)

DLN 2.6 Fuel Nozzle Arrangement
(typical)



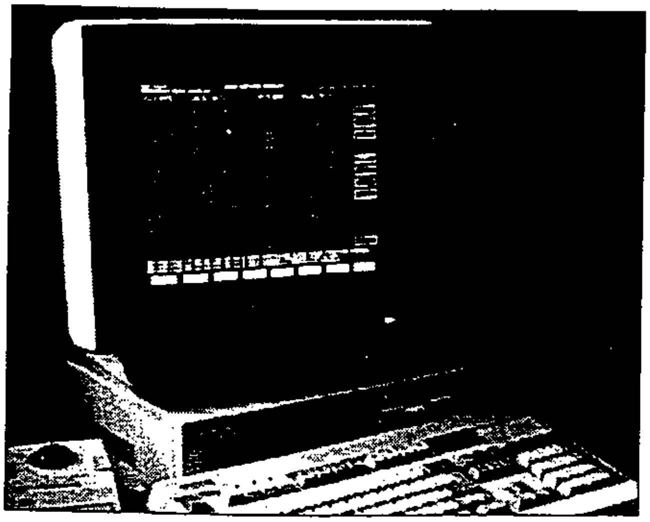


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Figure 10. Mark V operator interface

which ensures that no single hardware failure can interrupt communications between the gas turbine and the DCS system.

A specially configured PC is available to act as a "Historian," or <H> processor, for the gas turbine installation. All data available in the Mark V data base can be captured and stored by the historian. Analog data is stored when the values change beyond a settable deadband, and events and alarms are captured when they occur. In addition, data can be requested periodically or on demand in user definable lists. The historian is sized so that about a month's worth of data for a typical four unit plant can be stored on line, and provisions are included for both archiving and restoring older data. Display options include a full range of trending, cross-plotting and histogram screens.

Compliance with recognized standards is an important aspect of SPEEDTRONIC™ Mark V controls. It is designed to comply with several standards including the following:

ETL	– Approval has been obtained for labeling of the Mark V control panel, with ETL labeling of complete control cabs.
CSA/UL	– Approval has been obtained for the complete SPEEDTRONIC™ Mark V control panel.
UBC	– Seismic Code Section 2312 Zone 4.
ANSI	– B133.4 Gas Turbine Control and Protection System.
ANSI	– C37.90A Surge Withstand.

HARDWARE CONFIGURATION

The SPEEDTRONIC™ Mark V gas turbine control system is specifically designed for GE gas and steam turbines, and uses a considerable number of CMOS and VLSI chips selected to minimize power dissipation and maximize functionality. The new design dissipates less power than previous generations for equivalent panels. Ambient air at the panel inlet vents should be between 0 and 40 C (32 and 72 F) with a humidity between 5 and 95%, non-condensing. The standard panel is a NEMA 1A panel that is 90 inches high, 54 inches wide, 20 inches deep, and weighs approximately 1200 pounds. Fig. 11 shows the panel with doors closed.

For gas turbines, the standard panel runs on 125 volt DC unit battery power, with AC auxiliary input at 120 volt, 50/60 Hz, used for the ignition transformer and the <I> processor. The

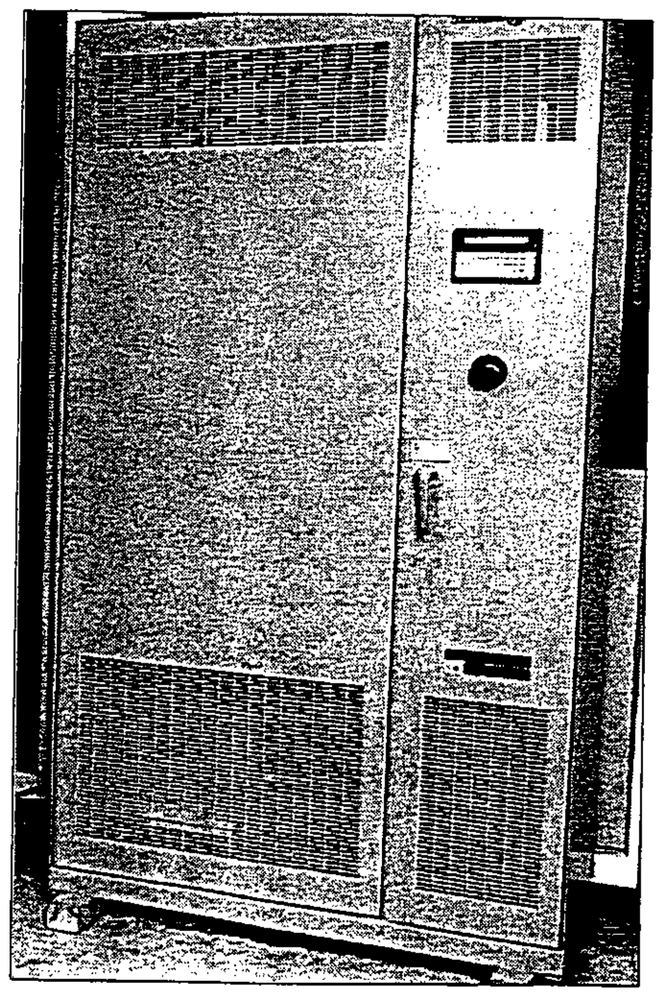

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Figure 11. Mark V turbine control panel

Transformers, a position sensor) produce a signal proportional to actuator position. Each control processor measures both LVDT signals and chooses the higher of the two signals. This value is chosen because the LVDT is designed to have a strong failure preference for low voltage output. The signal is compared with the position command and the error signal passed through a transfer function and a D/A converter to a current amplifier. The current amplifier from each control processor drives one of the three coils. The servo valve acts on the sum of the ampere turns. If one of the three channels fails, the maximum current that one failed amplifier can deliver is overridden by the combined signals from the remaining two good amplifiers. The result is that the turbine continues running under control.

The SIFT system ensures that the output fuel command signals to the digital servo stay in step. As a result, almost all single failures will not cause an appreciable bump in the controlled turbine parameter. Diagnostics of LVDT excitation voltage, LVDT outputs that disagree, and current not equalling the commanded value make it easy to find a system problem, so that on-line repair can be initiated quickly.

An independent protective module <P> is internally triple redundant. It accepts speed sensors, flame detectors, and potential transformer inputs to perform emergency electronic overspeed, flame detection, and synchronizing functions. Hardware voting for <P> solenoid outputs is accomplished on a trip card associated with the module. The trip card merges trip contact signals from the emergency overspeed, the main control processors, manual trip push buttons, and other hard-wired customer trips.

Overspeed and synchronization functions are independently performed in both the triple redundant control and triple redundant protective hardware, which reduces the probability of machine overspeed or out of phase synchronizing to the lowest achievable values.

SPEEDTRONIC™ Mark V control provides interfaces to DCS systems for plant control from the <I> processor. The two interfaces available are Modbus Slave Station and a standard Ethernet link, which complies with the IEEE-802.3 specification for the physical and medium access control (MAC) layers. A GE protocol is available for use over the Ethernet link. A hard-wired interface is also available.

Table 5 is a list of signals and commands available on the interfacing links. The table includes an option for hard-wired contacts and 4-20 ma signals intended to interface with older systems such as SCADA remote dispatch terminal units. The wires are connected to the I/O module associated with <C>.

Table 5
INTERFACING OPTIONS

Hardwired
- Connects to Common "C" Processor I/O
- Commands to Turbine Control
  - Turbine Start/Stop
  - Turbine Fast Load
  - Governor Set Point Raise/Lower
  - Base/Peak Load Selection
  - Gas/Distillate Fuel Selection
  - Generator Voltage (VARS) Raise/Lower
  - Generator Synchronizing Inhibit/Release
- Feedback From Turbine Control:
  - Watts, VARS and Volts (Analog for Meters)
  - Breaker Status
  - Starting Sequence Status
  - Flame on Indication
  - On Temperature Control Indication
- Alarm Management:
  - RS232C Data Transmission Only, From <I>

Modbus Link
- Turbine Control Is Modbus Slave Station
- Transmission on Request by Master, 300 to 19,200 Baud
- Connects to Interface Processor (I)
- RS232C Link Layer
- Commands Available:
  - All Allowable Remote Commands Are Available
  - Alarm Management
- Feedback From Turbine Control:
  - Most Turbine Data Available in the I Data Base

The "stage link" that interconnects the <C> processor with the <I> processor is an extendable Arcnet link that allows daisy chaining multiple gas turbines with multiple <I> processors. Thus a single gas turbine can be controlled from multiple <I> processors, or a single <I> processor can control multiple gas and steam turbines. For multi-unit configurations, the <I> processor can be equipped with plant load control capability that will allow plant level management of all units for both real and reactive power. The <I> processor, or Operator Interface, is shown in Fig. 10.

In process plants where maintaining the link to the DCS is essential to keeping the plant on-line, two <I> processors are used to obtain redundant links to the DCS system. For critical installations, a redundant <C> processor option, referred to as the <D> processor, is available

Table 4
CRITICAL REDUNDANT SENSORS

PARAMETER	TYPE	FUNCTION	USAGE	NUMBER
SPEED	MAG. PICKUP	CTL & PROT	DEDICATED	3 TO 6
EXHAUST TEMP.	T.C.	CTL & PROT	DEDICATED	13 TO 27
GENERATOR OUTPUT	TRANSDUCER	CONTROL	DEDICATED	3
LIQUID FUEL FLOW	MAG. PICKUP	CONTROL	DEDICATED	3
GAS FUEL FLOW	TRANSDUCER	CONTROL	DEDICATED	3
WATER FLOW	MAG. PICKUP	CONTROL	DEDICATED	3
ACTUATOR STROKE	LVDT	CONTROL	SHARED	2/ACTUATOR
STEAM FLOW	TRANSDUCER	CONTROL	SHARED	1
VIBRATION	SEISMIC PROBE	PROTECTION	SHARED	8 TO 11
FLAME	SCANNER	PROTECTION	SHARED	4 TO 8
FIRE	SWITCH	PROTECTION	SHARED	17 TO 21
CONTROL OIL PRES.	SWITCH	PROTECTION	SHARED	3
L.O. PRES.	SWITCH	PROTECTION	SHARED	3
L.O. TEMP.	SWITCH	PROTECTION	SHARED	3
EXH. FRAME BLWR.	SWITCH	PROTECTION	SHARED	2
FILTER DELTA P.	SWITCH	PROTECTION	SHARED	3

NOTES:
1. DEDICATED SENSORS: ONE-THIRD ARE CONNECTED TO EACH PROCESSOR.
2. SHARED SENSORS ARE SHARED BY PROCESSORS.
3. THE NUMBER OF EXHAUST THERMOCOUPLES IS RELATED TO THE NUMBER OF COMBUSTORS.
4. VIBRATION AND FIRE DETECTORS ARE RELATED TO THE PHYSICAL ARRANGEMENT.
5. GENERATOR OUTPUT TRANSDUCERS ARE REDUNDANT ONLY FOR "CONSTANT SETTABLE DROOP" SYSTEMS.
6. DRY LOW NO_x HAS FOUR FLAME DETECTORS IN EACH OF TWO ZONES.

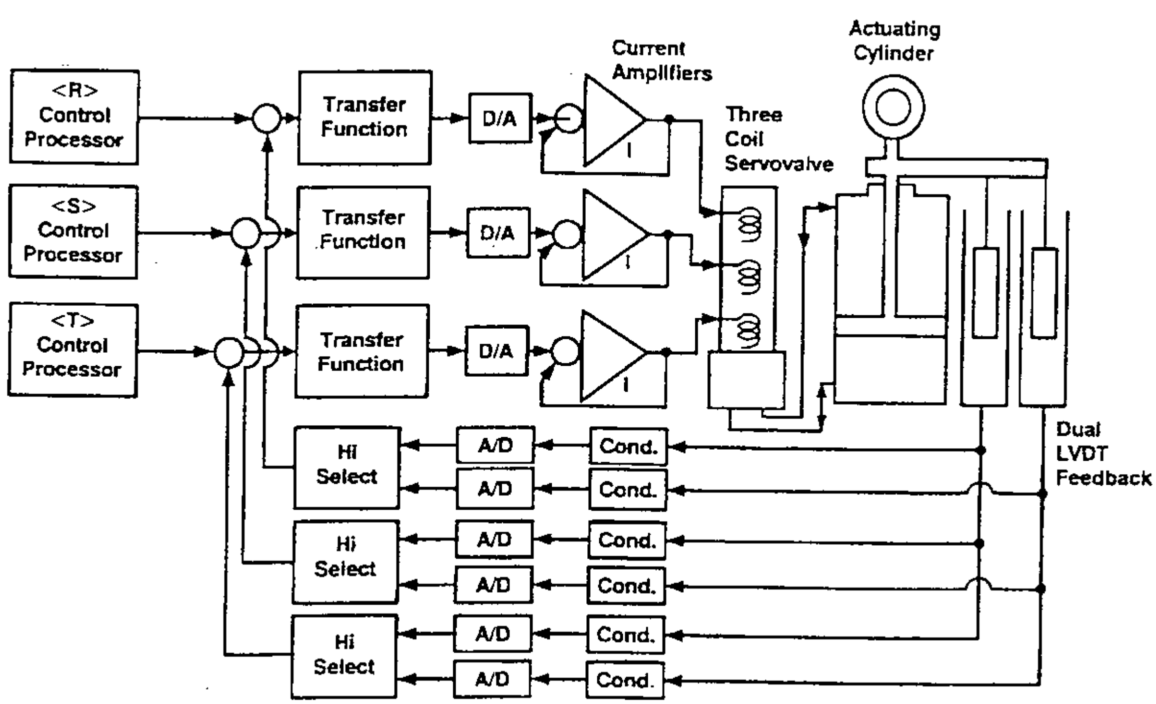

Figure 9. Digital servo position loops

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SPEEDTRONIC™ MARK V CONTROL CONFIGURATION

The SPEEDTRONIC™ Mark V control system makes increased use of modern microprocessors and has an enhanced system configuration. It uses SIFT technology for the control, a new triple-redundant protective module, and a significant increase in hardware diagnostics. Standardized modular construction enhances quality, speed of installation, reliability, and ease of on-line maintenance. The operator interface has been improved with color graphic displays and standardized links to remote operator stations and distributed control systems (DCS).

Figure 8 shows the standard SPEEDTRONIC™ Mark V control system configuration. The top block in the diagram is the Interface Data Processor, called <I>. It includes a monitor, keyboard, and printer. Its main functions are driving operator displays, managing the alarm process, and handling operator commands. <I> also does system configuration and download, off-line diagnostics for maintenance, and implements interfaces to remote operator stations and plant distributed control systems.

The Common Data Processor, or <C>, collects data for display, maintains the alarm buffers, generates and keeps diagnostic data, and implements the common I/O for non-critical signals and control actions. Turbine supervisory sensors such as wheelspace thermocouples come directly to <C>. The <I> processor communicates with <C> using a peer-to-peer communication link which permits one or more <I> processors. <C> gathers data from the control processors by participating on the voting link.

At the core of SPEEDTRONIC™ Mark V control are the three identical control processors, called <R> <S> and <T>. All critical control algorithms, turbine sequencing, and primary protective functions are handled by these processors. They also gather data and generate most of the alarms.

The three control processors accept input from various arrangements of redundant turbine and generator sensors. Table 4 lists typical redundant sensor arrangements. By extending the fault tolerance to include sensors, as with the Mark IV system, the overall control system availability is significantly increased. Some sensors are brought in to all three control processors, but many, like exhaust thermocouples, are divided among the control processors. The individual exhaust temperature measurements are exchanged on the voter link so that each control processor knows all exhaust thermocouple values. Voted sensor values are computed by each of the control processors. These voted values are used in control and sequencing algorithms that produce the required control actions.

One key output goes to the servo valves used in position loops as shown in Fig. 9. These position loops are closed digitally. Redundant LVDT's (Linear Variable Differential

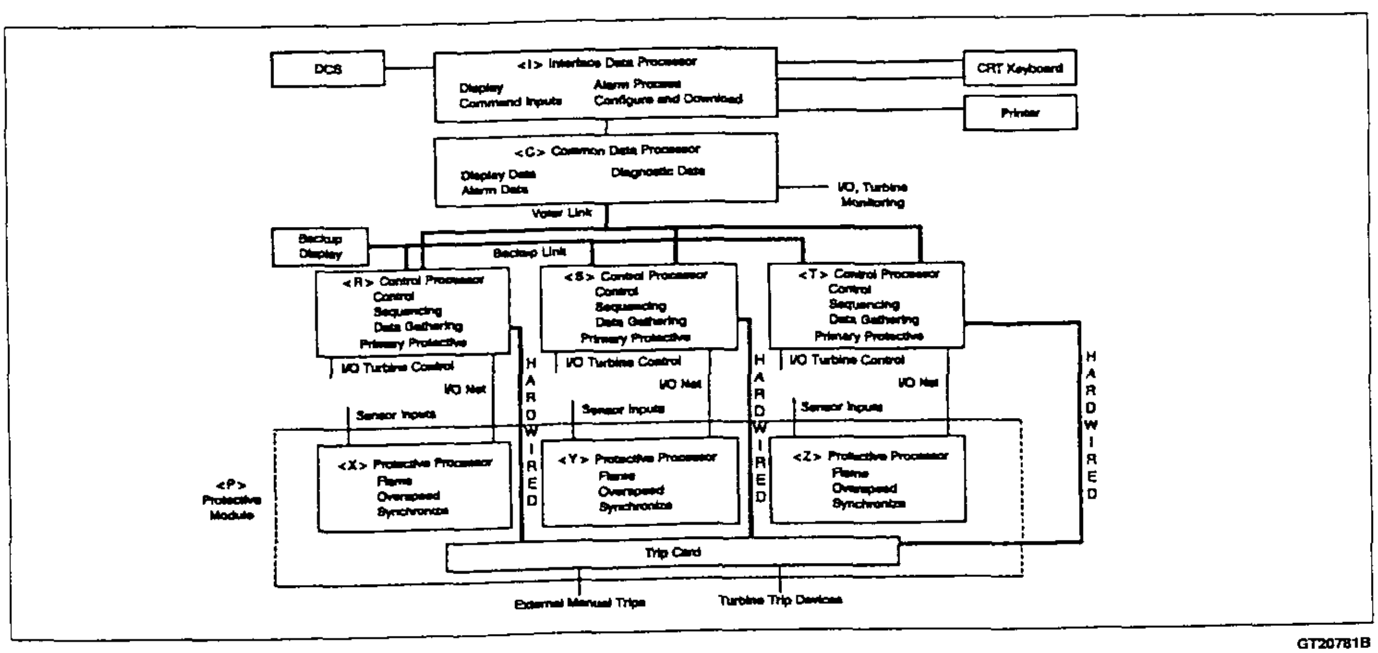

Figure 8. Standard control configuration

Gas turbines are capable of faster loading in the event of a system emergency. However, thermal fatigue duty for these fast load starts is substantially higher. Therefore, selection of a fast load start is by operator action, with the normal start being the default case.

Gas turbine generators that are equipped with diesel engine starting devices are optionally capable of starting in a blacked out condition, without outside electrical power. Lubricating oil for starting is supplied by the DC emergency pump, powered from the unit battery. This battery also provides power to the DC fuel forwarding pump for black starts on distillate. The turbine and generator control panels on all units are powered from the battery. An inverter supplies the AC power required for ignition and the local operator interface. Power for the cooling system fans is obtained from the main generator through the power potential transformer after the generator field is flashed from the battery at about 50% speed. The black start option utilizes a DC battery-powered turning device for rotor cool-down to ensure the integrity of the black start capability.

As mentioned previously, the protective function acts to trip the gas turbine independently from the fuel control in the event of overspeed, overtemperature, high rotor vibration, fire, loss of flame, or loss of lube oil pressure. With the advent of microprocessors, additional protective features have been added, with minimum impact on running reliability due to the redundancy of the microprocessors, sensors and signal processing. The added functions include combustion and thermocouple monitoring, high lube oil header temperature, low hydraulic supply pressure, multiple control computer faults, and compressor surge for the aircraft-derivative gas turbines.

Because of their nature or criticality, some protective functions trip the stop valve through the hard-wired, triple-redundant protective module. These functions are the hard-wired overspeed detection system, which replaces the mechanical overspeed bolt on some units, the manual emergency trip buttons, and "customer process" trips. As previously mentioned, the protection model performs the synchronization function to close the breaker at the proper instant. It also receives signals from the flame detectors and determines if flame is on or off. A block diagram of the turbine protective system is shown in Fig. 7. It shows how loss of lube oil, hydraulic supply, or manual hydraulic trip will result in direct hydraulic actuation of the stop valves.

Interfacing to other application-specific trip functions is provided through the three control processors, the hard-wired protection module, or the hydraulic trip system. These trip functions include turbine shutdown for generator protective purposes, and combined-cycle coordination with heat recovery steam generators and single-shaft STAG™ steam turbines. The latter is hydraulically integrated as shown in Fig. 7. Other protective coordination is provided as required to meet the needs of specific applications.

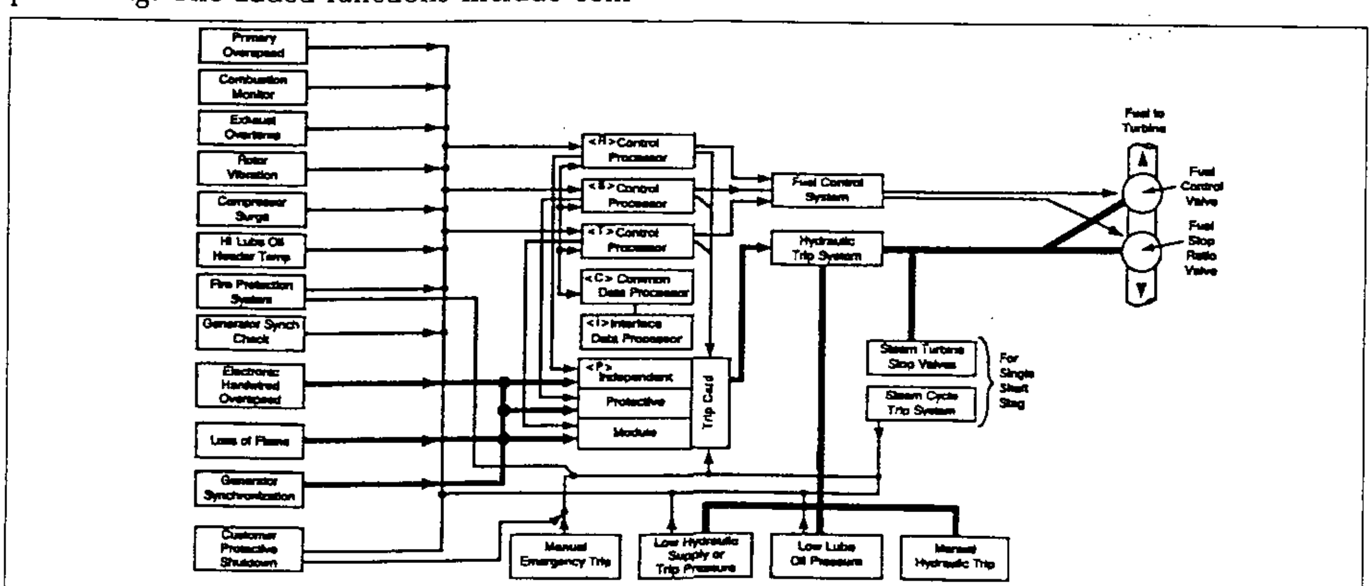

Figure 7. Protective system block diagram; SPEEDTRONIC™ Mark V turbine control

mined program of acceleration rates, slower initially, and faster just before reaching running speed. The purpose of this is to reduce the thermal fatigue duty associated with startup.

At about 40 to 85% speed, turbine efficiency has increased sufficiently so that the gas turbine becomes self sustaining, and external cranking power is no longer required. At about 80 to 90% speed, the compressor inlet guide vanes, which were closed during startup to prevent compressor surge, are opened to the full-speed, no-load position.

As the turbine approaches running speed, synchronizing is initiated. This is a two or three step process that consists of matching turbine generator speed, and sometimes voltage, to the bus, and then closing the breaker at the point where the two are in phase within predetermined limits.

Turbine speed is matched to the line frequency with a small positive differential to prevent the generator breaker from tripping on reverse power at breaker closure. In the protective module, triple redundant micro-processor-based synchronizing methods are used to predict zero phase angle difference and compensate for breaker closing time to provide true zero angle closure. Acceptable synchronizing conditions are independently verified by the triple redundant control processors as a check function.

At the completion of synchronizing, the turbine will be at a spinning reserve load. The final step in the starting sequence consists of automatic loading of the gas turbine generator, at either the normal or fast rate, to either a preselected intermediate load, base load, or peak load. Typical starting times to base load are shown in Table 3. Although the time to full speed no load applies to all simple cycle gas turbines, the loading rates shown are for standard combustion, and may vary for some dry low NO_x systems.

Normal shutdown is initiated by the operator, and is reversible until the breaker is opened and the turbine operating speed falls below 95%. The shutdown sequence begins with automatic unloading of the unit. The main generator breaker is opened by the reverse power relay at about five percent negative power, which drives the gas turbine fuel flow to a minimum value sufficient to maintain flame, but not turbine speed. The gas turbine then decelerates to about 40 to 25% speed, where fuel is completely shut off. As before, the purpose of this "fired shutdown" sequence is to reduce the thermal fatigue duty imposed on the hot gas path parts.

After fuel is shut off, the gas turbine coasts down to a point where the rotor turning system can be effective. The rotor should be turned periodically to prevent bowing from uneven cool-down, which would cause vibration on subsequent start-ups. Turning of the rotor for cool-down or maintenance is accomplished by a ratcheting mechanism on the smaller gas turbines, or by operation of a conventional turning gear on some larger gas turbines. Normal cool-down periods vary from five hours on the smaller turbines to as much as forty-eight hours on some of the larger units. Cool down sequences may be interrupted at any point for a restart if desired.

Table 3
SIMPLE CYCLE PACKAGE POWER PLANT STARTING TIMES

Model Series	Type of Start	Starting Device	Minutes: Diesel Warmup Time	+	Turbine Starting Time	=	Time to Full Speed No Load	Total Time to Base Load
LM6000	Normal	Hydraulic	NA		7.0		7.0	12.0
MS5001P	Normal	Diesel	2		7.17		9.17	13.17
	Fast Load	Diesel	1/2		7.17		7.67	9.67
	Emergency	Big Diesel	1/2		4.0		4.5	5.0
MS6001B	Normal	Diesel	2		10.0		12.0	16.0
	Fast Load	Diesel	1/2		6.67		7.17	9.17
MS7001EA	Normal	Motor	NA		7.5		7.5	19.5
	Fast Load	Motor	NA		7.5		7.5	9.0
MS7001FA	Normal	Motor/LCI	NA		9.0		9.0	21.0
MS9001E	Normal	Motor	NA		8.17		8.17	20.17
	Fast Load	Motor	NA		8.17		8.17	9.67
MS9001FA	Normal	Motor/LCI	NA		9.0		9.0	21.0

LCI = Load Commutating Inverter (Static Starter)

LIST OF FIGURES

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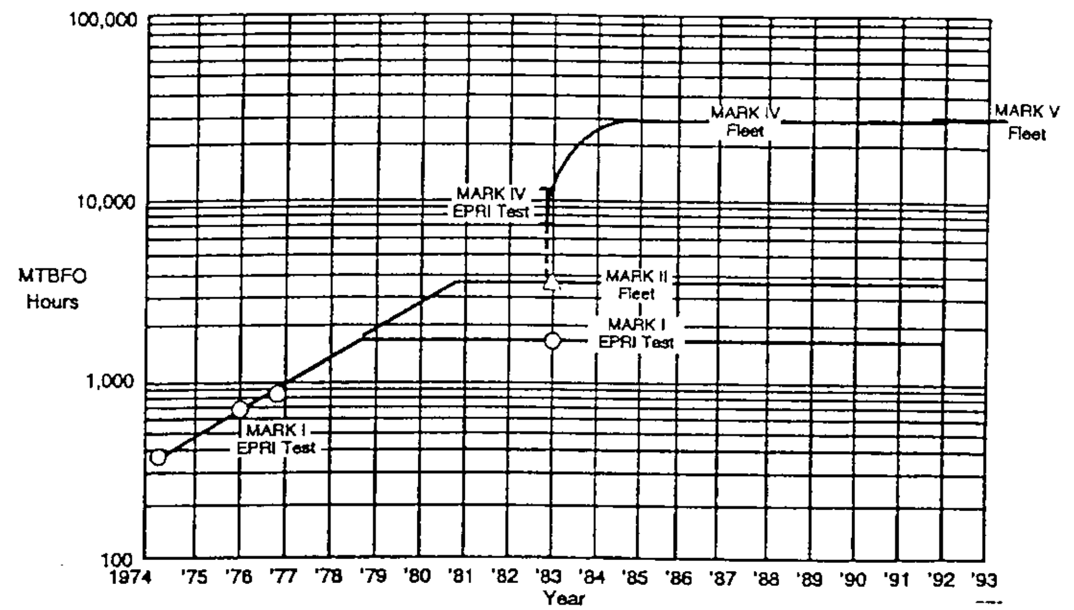


Figure 15. Control system reliability

components to fail, and fewer types of components in the control panel. (This also means that there are fewer spares to stock.) Two-out-of-three redundancy on critical functions and components ensures that failures, which are less likely to begin with, are also less likely to cause a turbine trip. Extensive built-in diagnostics and the ability to replace almost any component while running further minimize exposure time, while running with a failed component when the potential to trip resulting from a double failure, is highest. Finally, the high degree of standardized, yet still flexible, software and hardware allowed a much greater degree of automated manufacturing and testing, substantially lowering the potential for human error, and increasing the repeatability of the process.

The Mark V system is a further improvement over the Mark IV system. Although the two-out-of-three voting philosophy is retained, its implementation is improved and made more robust through use of Software Implemented Fault Tolerance techniques. Components, and types of components, have been further reduced in number. Standardization of hardware and software has been carried several steps further, but flexibility has also been increased. Greater degrees of automated manufacturing and testing have been complimented by greater utilization of computer-aided engineering to standardize the generation and testing of software and system configuration. Thus, it is fully expected the Mark V system will further advance the continuing growth of gas turbine control system starting and running reliability.

SUMMARY

The SPEEDTRONIC™ Mark V Gas Turbine Control System is based on a long history of successful gas turbine control experience, with a substantial portion using electronic and microprocessor techniques. Further advancements in the goals of starting and running reliability, and system availability will be achieved by logical evolution of the unique architectural features developed and initially put into service with the Mark IV system. Flexibility of application and ease of operation will also grow to meet the needs of generator and mechanical drive systems, in process and utility operating environments, and in both peaking and base load service.

REFERENCES

1. W.I. Rowen, "Operating Characteristics of Heavy Duty Gas Turbines in Utility Service," ASME Paper #88-GT-150, presented at the Gas Turbine and Aeroengine Congress, Amsterdam, The Netherlands – June 6-9, 1988.

diagnostic routine. It is an indicator of degradation in the ultraviolet flame detection system.

In another example, the contact input circuits can be forced to either state and then be interrogated to ensure that the circuit functions correctly without disturbing their normal operation. The extent of this kind of diagnostics has been greatly increased in SPEEDTRONIC™ Mark V control over previous generations. This level of monitoring and diagnostics makes maintenance easier and faster so that the control system stays in better repair. A properly maintained panel is highly fault tolerant and makes systems starting and running reliability approach 100%.

Once the diagnostic routines have located a failed part, it may be replaced while the turbine continues to run. The most critical function of the diagnostics is to identify the proper control section where the problem exists. Wrong identification could lead to powering down a good section, resulting in a vote to trip. If the failed section is also voting to trip, the turbine will trip. A great deal of effort has been put into identifying the correct section. To effect the repair, the correct section is powered down. The module is opened and tilted out, the offending card located, cables disconnected, card replaced, and cables reconnected. The rack is closed and power is reapplied to the module. The module will then join in with the others to control the turbine, and the fault tolerance is restored.

Should the fault be in the <I> or <C> processor, it is likely that the operator display will stop or go blank, and that commands can no longer be sent by the operator to the turbine from <I>. This upsets the operator much more than it disturbs the control processors or turbine. A back-up display is provided to handle this situation. It happens very infrequently, and repair of the normal operator interface will usually be accomplished in less than three hours. Optional redundant <I> processors make the use of the back-up display even more unlikely. The gas turbine control is completely automatic and needs little human intervention for starting, running, stopping, or tripping once a sequence is initiated.

The back-up display provides for a minimum set of control commands: start, stop, raise load, and lower load. It reports all process alarms by number. Since the alarm text can be altered on site in <I>, a provision is included to print the alarms with their internal alarm numbers. This list is used to look up the alarm name from the alarm number. The same is true for data points; however, a preselected list of key data points are programmed into the back-up panel which display the short symbol name, value, and engineering units. The control ships from the factory with this limited list of key parameters established for the back-up display.

CONTROL SYSTEM EXPERIENCE

The SPEEDTRONIC™ Mark V Turbine Control System was initially put into service in May of 1992 on one of three industrial generator drive MS9001B gas turbines. The system was subsequently put into utility service on two peaking gas turbines to obtain experience in daily starting service in order to develop a starting reliability assessment in addition to the continuous duty running reliability assessment. General product line shipments of the Mark V System on new unit production commenced early in 1993, with new installations starting up throughout the second half of that year.

Today, virtually all turbine shipments include Mark V Turbine Controls. This includes 424 new gas turbines, and 106 new steam turbines either shipped or on order. In addition, almost eighty existing units have been committed to retrofitted SPEEDTRONIC™ Mark V Turbine Control Systems, however, the bulk of these are designed as Simplex rather than the triple redundant systems associated with new units. This is due to the floor space available in retrofit applications. Reliability of the in service fleet, subsequent to commissioning and after accumulating over 1.4 million powered operational hours on 264 units, has been as expected. Indicated MTBFO (Mean-Time-Between-Forced-Outages) is in excess of 28,000 hours for the system, which includes control panel, sensors, actuators, and all intervening wiring and connectors. This performance is shown relative to the rest of the electronic control history in Figure 15.

Why is the Mark V system so much better than its predecessors? First of all, there are fewer

Displays for normal operation center around the unit control display. It shows the status of major selections and presents key turbine parameters in a table that includes the variable name, value, and engineering units. A list of the oldest three unacknowledged alarms appears on this screen. The operator interface also supports an operator-entered list of variables, called a user defined display, where the operator can type in any turbine-generator variable, and it will be added to the variable list. Commands that change the state of the turbine require an arm activate sequence to avoid accidental operation. The exception is setpoint incrementing commands, which are processed immediately and do not require an arm-activate sequence.

Alarm management screens list all the alarms in the chronological order of their time tags. The most recent alarm is added to the top of the display list. The line shows whether the alarm has been acknowledged or not, and whether the alarm is still active. When the alarm condition clears, the alarm can be reset. If reset is selected and the alarm has not cleared, the alarm does not clear and the original time tag is retained.

The alarm log prints alarms in their arrival sequence, showing the time tags which are sent from the control modules with each alarm. Software is provided to allow printing of other information, such as copying of text screens, or making a listing of the full text of all alarms or turbine variables. When the printer has been requested to make such an output, it will form feed, print the complete list, and form feed again. Any alarms that happened during the time of printing were stored and are now printed. An optional alternative is to add a second printer, dedicating one to the alarm log.

Administrative displays help with various tasks such as setting processor real time clocks and the date. These displays will include the selection of engineering units and allow changing between English and metric units.

There are a number of diagnostic displays that provide information on the turbine and on the condition of the control system. A partial list of the diagnostics available is presented in Table 7. The trip diagnostic screen traps the actual signal condition that caused a turbine trip. This display gives detailed information about the actual logic signal path that caused any trip. It is accomplished by freezing information about the logic path when the trip occurs. This is particularly useful in identifying the original source of trouble if a spurious signal manages to cause one of the control processors to call for a trip and does not leave a normal diagnostic trail. In SPEEDTRONIC™ Mark V controls, all trips are annunciated, and information about the actual logic path that caused the trip is captured. In addition to this information, contact inputs are resolved to one millisecond, which makes this sequence of events information more valuable.

Table 7
MONITORING AND DIAGNOSTICS

- Power
  - Incoming Power Sources
  - Power Distribution
  - All Control Voltages
  - Battery Ground, Non-Interfering With Other Ground Detectors
- Sensors and Actuators -
  - Contact Inputs Circuits; Can Force and Interrogate
  - Open Thermocouple
  - Open and Short on Seismic Vibration Transducers
  - LVDT Excitation Voltage
  - Servovalve Current Feedback Loopback Test
  - 4/20 MA Control Outputs - Loopback Testing
  - Relay Driver; Voting Current Monitor
  - RTD Open and Short
- Protective
  - Flame Detector; UV Light Level Count Output
  - Synchronizer - Phase Angle at Closure
  - Trip Contact Status Monitor
- Voted Data -
  - Voting Mismatch

The previously mentioned comparison of voting values is another powerful diagnostic tool. Normally these values will agree, and significant disagreement means that something is wrong. Diagnostic alarms are generated whenever there is such a disagreement. Examination of these records can reveal what has gone wrong with the system. Many of these combinations have specific diagnostics associated with them, and the software has many algorithms that infer what has gone wrong from a pattern of incoming diagnostic signals. In this way the diagnostic alarm will identify as nearly as possible what is wrong, such as a failed power supply, blown fuse, failed card, or open sensor circuit.

Some of the diagnostics are intended to enhance turbine-generator monitoring. For instance, reading and saving the actual closing time of the breaker is an excellent diagnostic on the health of the synchronizing system. An output from the flame detectors which shows the effective ultraviolet light level is another new tective function in the control processors, each activate a relay driver. The driver signals are sent to the trip card in the protective model where independent relays are actuated. Contacts from each of these three primary protective trip relays are voted to cause the trip solenoid to drop out. Separate overspeed pickups are brought to the independent protective module. Their relay contacts are wired in a voting arrangement to the other side of the trip solenoid, and independently cause the trip solenoid to drop out on detection of overspeed.

The <I> processor is equipped with a hard disk which keeps the records that define the site software configuration. It comes from GE with the site-specific software properly configured. For most upgrades, the basic software configuration on the disk is replaced with new software from the GE factory. The software is quite flexible, and most required alterations can be made on site by qualified personnel. Security codes limit access to the programs used to change constants and sequencing, do logic forcing, manual control, and so forth. These codes are under the control of the owner, so that if there is a need to change access codes, new ones can be established on site. Basic changes in configuration, such as an upgrade to turbine capability, requires that the new software be compiled in <I> and downloaded to the processor modules. The information for <C> is stored in EEPROM there. The information for the control processors is passed through <C> and stored in EEPROM in <R> <S> and <T>. Once the download is complete, the <I> processor can fail and the turbine will continue to run properly, accepting commands from the local backup display, while <I> is being repaired.

Changes in control constants can be accomplished on-line in working memory. For example, a new set of tuning constants can be tried. If they are found to be satisfactory, they can be uploaded for storage in <I>, where they will be retained for use in any subsequent software download. <I> also keeps a complete list of variables, which can be displayed and printed.

The most critical algorithms for protective, control, and sequencing have evolved over many years of GE gas turbine experience. These basic algorithms are in EPROM. They are tuned and adapted with constants that are field adjustable. By protecting these critical algorithms from inadvertent change, the performance and safety of the complete fleet of GE gas turbines is made more secure.

OPERATION AND MAINTENANCE

The operator interface is comprised of a VGA color graphics monitor, keyboard, and printer. The functions available on the operator interface are shown in Table 6.

Table 6
OPERATOR INTERFACE FUNCTIONS

- Control
  - –Unit Control
  - –Generator Control (or Load Control)
  - –Alarm Management
  - –Manual Control (Examples)
    - •Preselected Load Setpoint
    - • Inlet Guide Vane Control
    - •Isochronous Control
    - •Fuel Stroke Reference
    - •Auxiliary Control
    - •Water Wash
    - •Mechanical Overspeed Test
- Data (Examples)
  - –Exhaust Temperatures
  - –Lube Oil Temperatures
  - –Wheelspace Temperatures
  - –Generator Temperatures
  - –Vibration
  - –Timers and Event Counters
  - –Emission Control Data
  - –Logical Status
    - •Contracts In
    - •Relay Out
    - •Internal Logic
  - –Demand Display
    - •Periodic Logging
- Administrative–
  - –Set Time/Date
  - –Select Scale Units
  - –Display Identification Numbers
  - –Change Security Code
    - •Maintenance/Diagnostics
  - –Control Reference
  - –Configuration Tools
  - –Tuning Tools
    - •Constant Change Routines
  - –Actuator Auto-Calibrate
  - –Trip Display
  - –Rung Display
  - –Logic Forcing
  - –Diagnostic Alarms
  - –Diagnostic Displays
    - •Off Line
    - •On Line
  - –System Memory Access

SOFTWARE CONFIGURATION

Improved methods of implementing the triple modular redundant system center on SIFT (Software Implemented Fault Tolerance) technology and result in a more robust control. SIFT involves exchanging information on the voter link directly between <R> <S> <T> and <C> controllers. Each control processor measures all of its input sensors so that each sensor signal is represented by a number in the controller. The sensor numbers to be voted are gathered in a table of values. The values of all state outputs such as integrators, for example the load setpoint, are added to the table. Each control processor sends it's table out on the voter link and receives tables from the other processors. Consider the <R> controller: it outputs its table to, and receives the tables from, the <S> and <T> controllers. Now all three controller tables will be in the <R> processor which selects the median value for each sensor and integrator output, and uses these voted outputs in all subsequent calculations. <S> and <T> follow the same procedure.

The basic SIFT concept, then, brings one sensor of each kind into each of <R> and <S> and <T>. If a sensor fails, the controller with the failed transducer initially has a bad value. But it exchanges data with the other processors, and when the voting takes place, the bad value is rejected. Therefore, a SIFT based system can tolerate one failed transducer of each kind. In previous systems, one failed transducer was likely to cause one processor to vote to trip. A failure of a different kind of transducer on another controller could cause a turbine trip. This does not happen with SIFT because the input data is exchanged and voted.

<C> is also connected to the voter link. It eavesdrops while all three sets of variables are transmitted by the control processors and calculates the voted values for itself. If there are any significant disagreements, <C> reports them to <I> for operator attention and maintenance action. If one of the transducers has failed, its output will not be correct and there will be a disagreement with the two correct values. <C> will then diagnose that the transducer, or parts immediately associated with it, have failed and will post an alarm to <I>.

Voting is also performed on the outputs of all integrators and other state variables. By exchanging these variables, fewer bumps in output are caused when a failure or a repair takes place. For instance, if a turbine is set to run on isochronous speed control with an isolated load, there is an integrator that compares the frequency of the generator with the nominal frequency reference (50 or 60 Hz). Any error is integrated to produce the fuel command signal. If one computer calculates an erroneously high fuel command, nothing happens because the processors will exchange the fuel command and vote, and all will use the correct value of fuel command. When the processor is repaired and put back in service, its fuel command will initially be set to zero. But as soon as the first data is exchanged on the voter link, the repaired control processor will output the voted value which will be from one of the running processors, so no bump in fuel flow will occur. No special hardware or software is needed to keep integrated outputs in step.

Since there is only one turbine connected to each panel, the triple-redundant control information must be recombined. This recombination is done in software or, for more critical signals, in dedicated voting hardware. For critical outputs, such as the fuel command, the recombination of the signals is done by the servo valve on the turbine itself as previously explained.

For example, up to four critical 4 to 20 ma outputs are voted in a dedicated electronic circuit. The circuit selects the median signal for output. It takes control power for the electronics and the actual output current from all three sections such that any two control sections will sustain the correct output. Non-critical outputs are software voted and output by the I/O associated with <C>.

Logic outputs are voted by dedicated hardware relay driver circuits that require two or three "on" signals to pick up the output relay. Control power for the circuit and output relay is taken from all three control sections.

Protective functions are accomplished by the control processors and, for overspeed, independently by the Protective Module <P> as well. Primary speed pickups are wired to the control processors and used for both speed control and primary overspeed protection. The trip commands, generated by the primary overspeed protypical standard panel will require 900 watts of DC and 300 watts of auxiliary ac power. Alternatively, the auxiliary power can be 240 volt AC 50 Hz, or it can be supplied from an optional black start inverter from the battery.

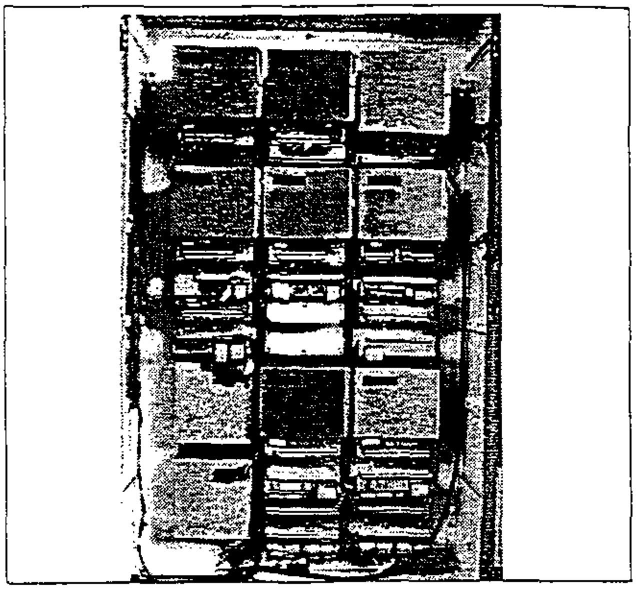
The power distribution module conditions the power and distributes it to the individual power supplies for the redundant processors through replaceable fuses. Each control module supplies its own regulated DC busses via DC/DC converters. These can accept an extremely wide range of incoming DC, which makes the control tolerant of significant battery voltage dips, such as those caused by starting a diesel cranking motor. All power sources and regulated busses are monitored. Individual power supplies can be replaced while the turbine is running.

The Interface Data Processor, particularly a remote <I>, can be powered by house power. This will normally be the case when the central control room has an Uninterruptible Power Supply (UPS) system. AC for the local <I> processor will normally be supplied via a cable from the SPEEDTRONIC™ Mark V panel or alternatively from house power.

The panel is constructed in a modular fashion and is quite standardized. A picture of the panel interior is shown in Fig. 12, and the modules are identified by location in Fig. 13. Each of these modules is also standardized, and a typical processor module is shown in Fig. 14. They feature card racks that tilt out so cards can be individually accessed. Cards are connected by front-mounted ribbon cables which can be easily disconnected for service purposes. Tilting the card rack back in place and closing the front cover locks the cards in place.

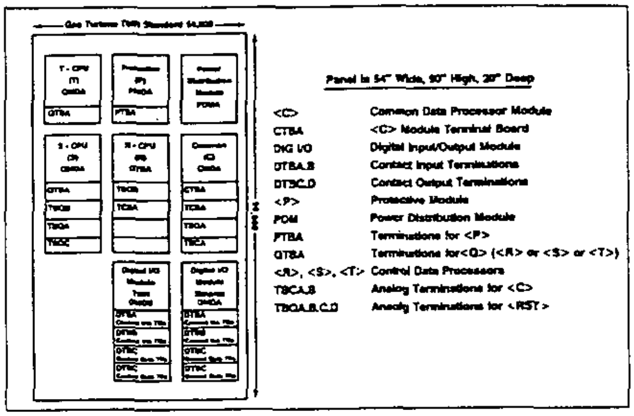
Considerable thought has been given to the routing of incoming wires to minimize noise and crosstalk. The wiring has been made more accessible for ease of installation. Each wire is easily identified and the resulting installation is neat.

The panels are made in a highly standardized manufacturing process. Quality control is an integral part of the manufacturing; only thoroughly tested panels leave the factory. By having a highly controlled process, the resulting modules and panels are very consistent and repeatable.



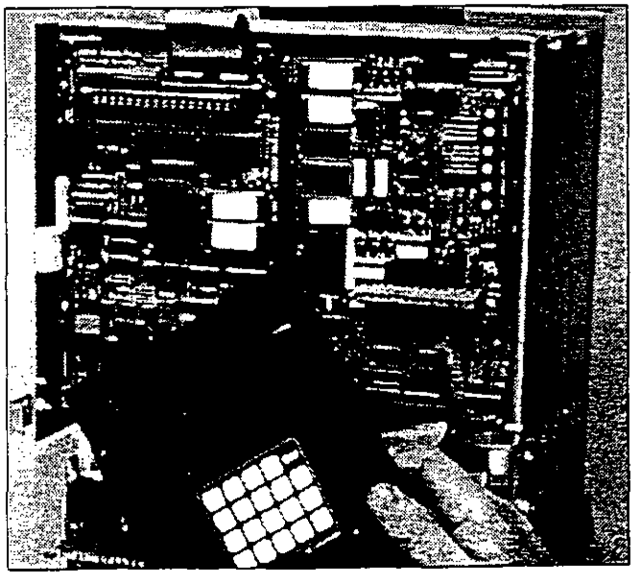
RDC26449-2-8

Figure 12. Panel internal arrangement



GT20783A

Figure 13. Module map of panel interior



GT21533A

Figure14. Typical processor module

Exhibit D

Combustion Turbine

Start-Up / Shut-Down

Data

06/19/98 GRS

Combined Cycle Startup Curves

Notes

I) The units for accumulated heat consumption used in these curves are %-hr. A value of 100 %-hr is the heat consumption of the unit at base load ISO ambient for one hour. To convert the value from a curve in %-hr to engineering units multiply the curve value of %-hr by the quantity, base heat consumption for the unit in engineering units divided by 100%.

Ex/ Accumulated heat consumption to complete the start is 28 %-hr as read from the curve. If base heat consumption is 545.2 M Kcal/hr LHV, then the estimated startup heat consumption is,

$$28\ \%\text{-hr} \times \frac{545.2\ \text{M Kcal}}{\text{hr} \times 100\ \%} = 152.7\ \text{M Kcal}$$

or 28% of heat consumption at base for an hour.

II) The starts are defined by the amount of time the unit has been shutdown, following the normal (hot) shutdown procedure, prior to the startup.

Hot start = 8 hours prior shutdown
Warm start = 48 hours prior shutdown
Cold start = 72 hours prior shutdown

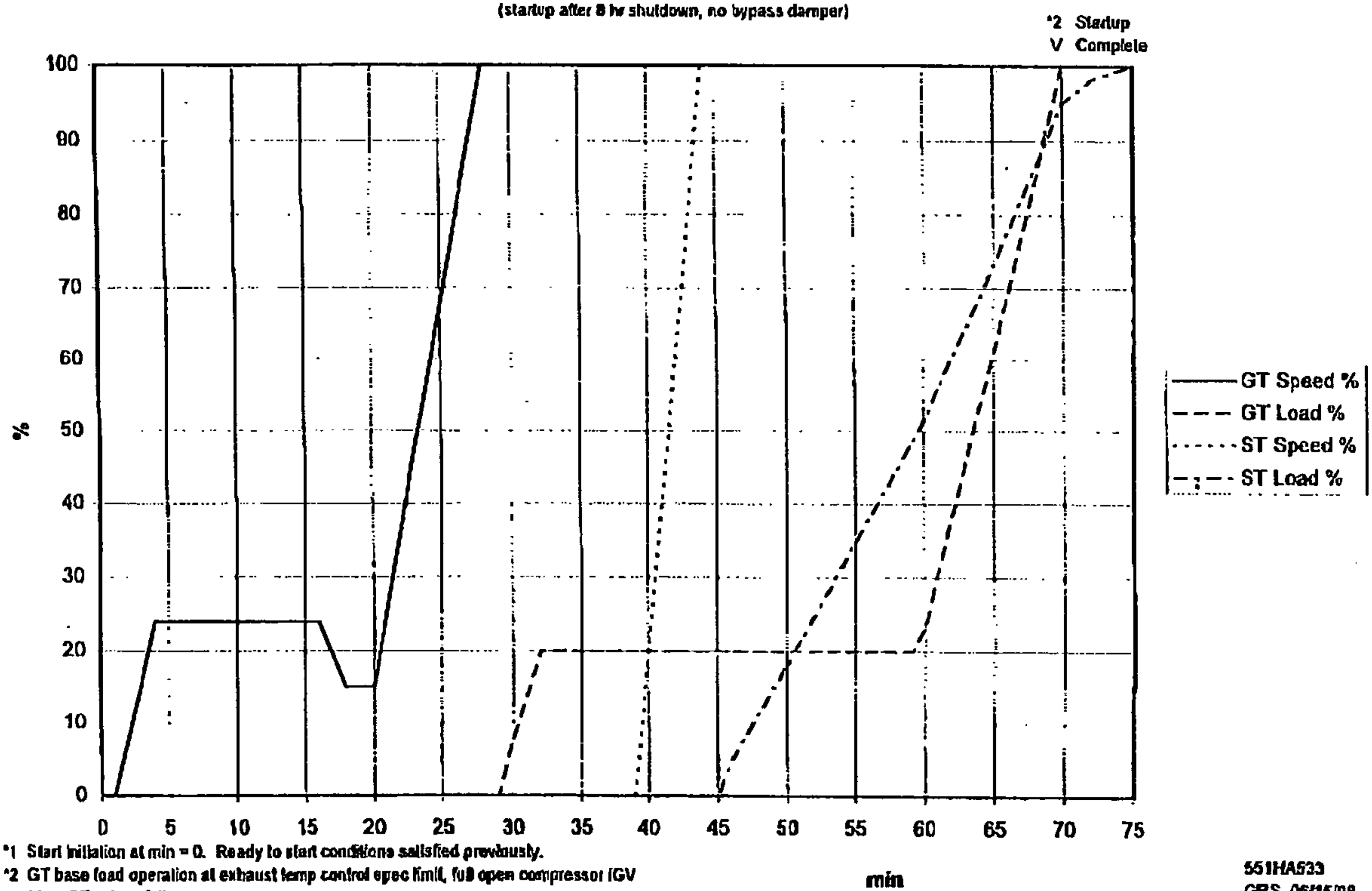
III) The definition of start used here is from unit rolloff of turning gear to the time the GT (or GTs) get to base load with the ST in Inlet Pressure Control IPC meaning the steam bypasses are shut and the plant is operating in a Combined Cycle mode. Not included in this Interval is the continued increase in ST output due to the steam cycle lag, primarily characterized by the HRSG time constant, following the time when GT(s) reach base. The time at which the ST actually reaches base load is not practical to determine for test purposes due to the gradually increasing load characteristic of the ST after the GT(s) reach base

IV) Assumed prestart conditions include ST sealing steam is on and condenser vacuum established. If a source of sealing steam is not available prior to startup, for example from an auxiliary boiler, a previously running unit, a nearby steam source, etc., then the starting time will be increased by the time required to establish ST seals and pull vacuum, typically 30 minutes.

V) The curves were created based on ISO conditions. Certain parameters such as the GT load used for initial steam temperature setting will vary somewhat for non-ISO ambient conditions. For example, the GT load used for hot start is 20% based on ISO ambient temperature. At 0 deg F ambient it would be 10% and 120 deg F ambient would give 28%.

Typical 107FA Hotstart (multishaft)

(startup after 8 hr shutdown, no bypass damper)

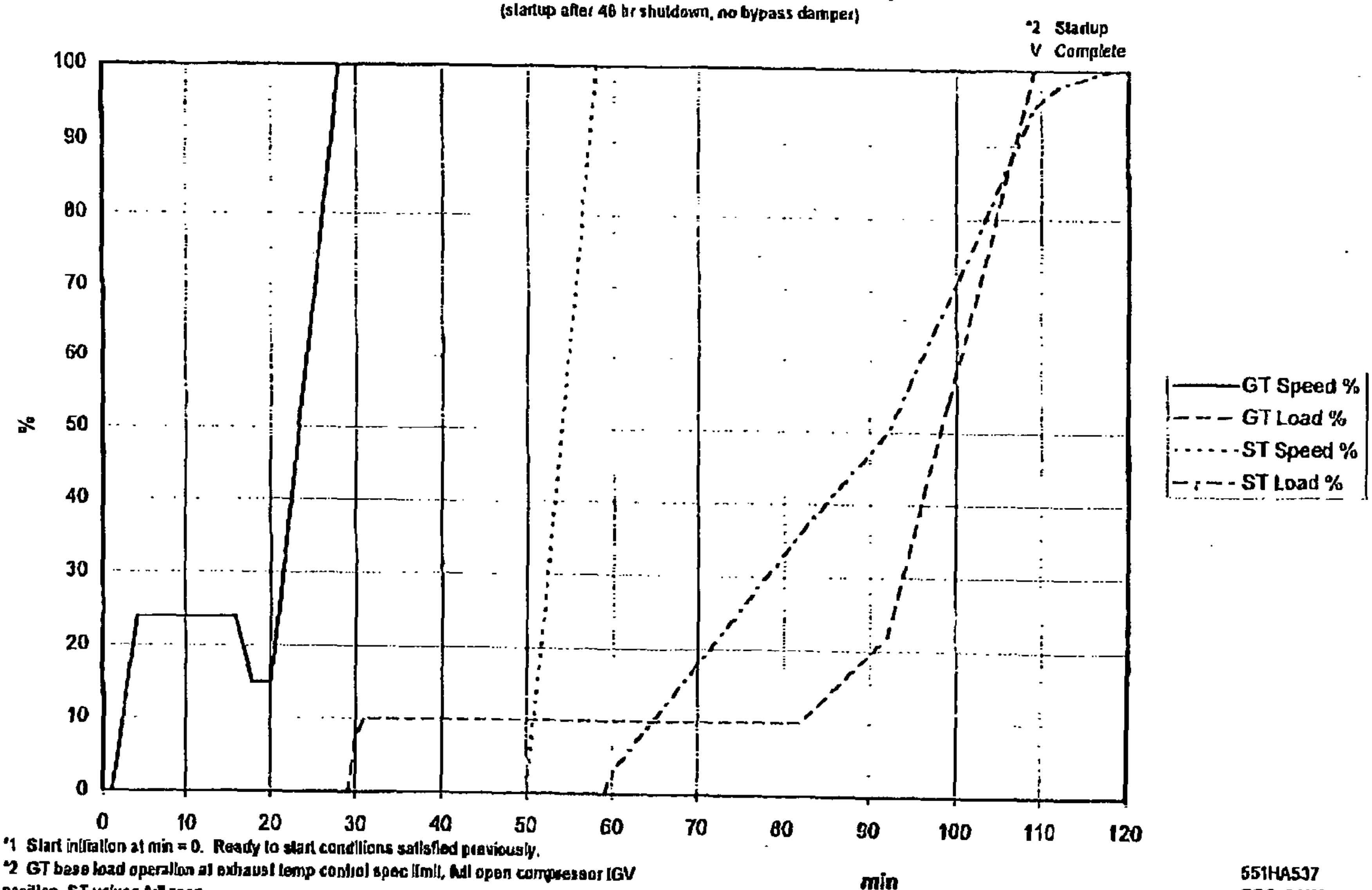


*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA533
GRS 06/15/98

Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)

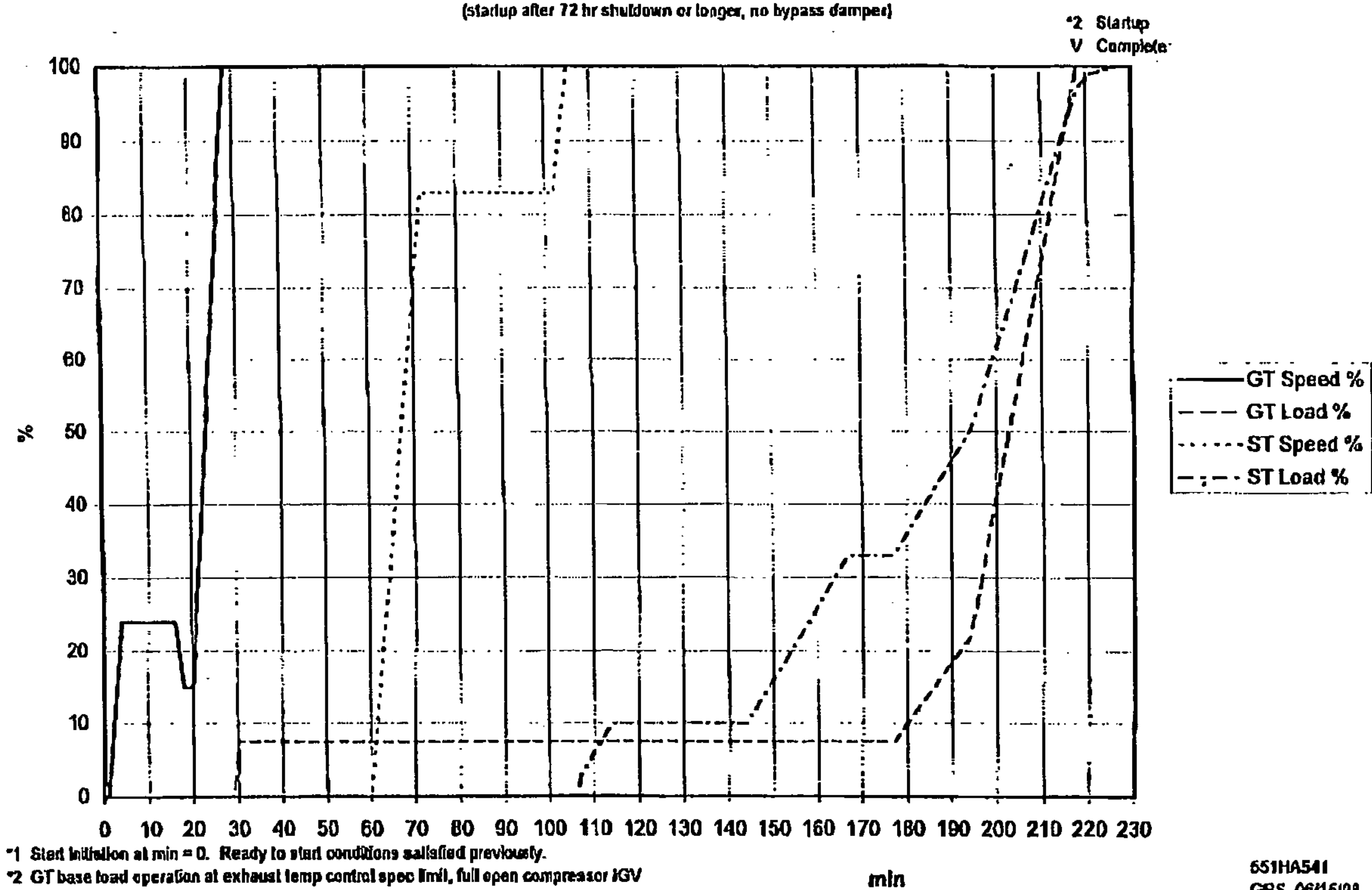


*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA537
GRS 06/15/98

Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)

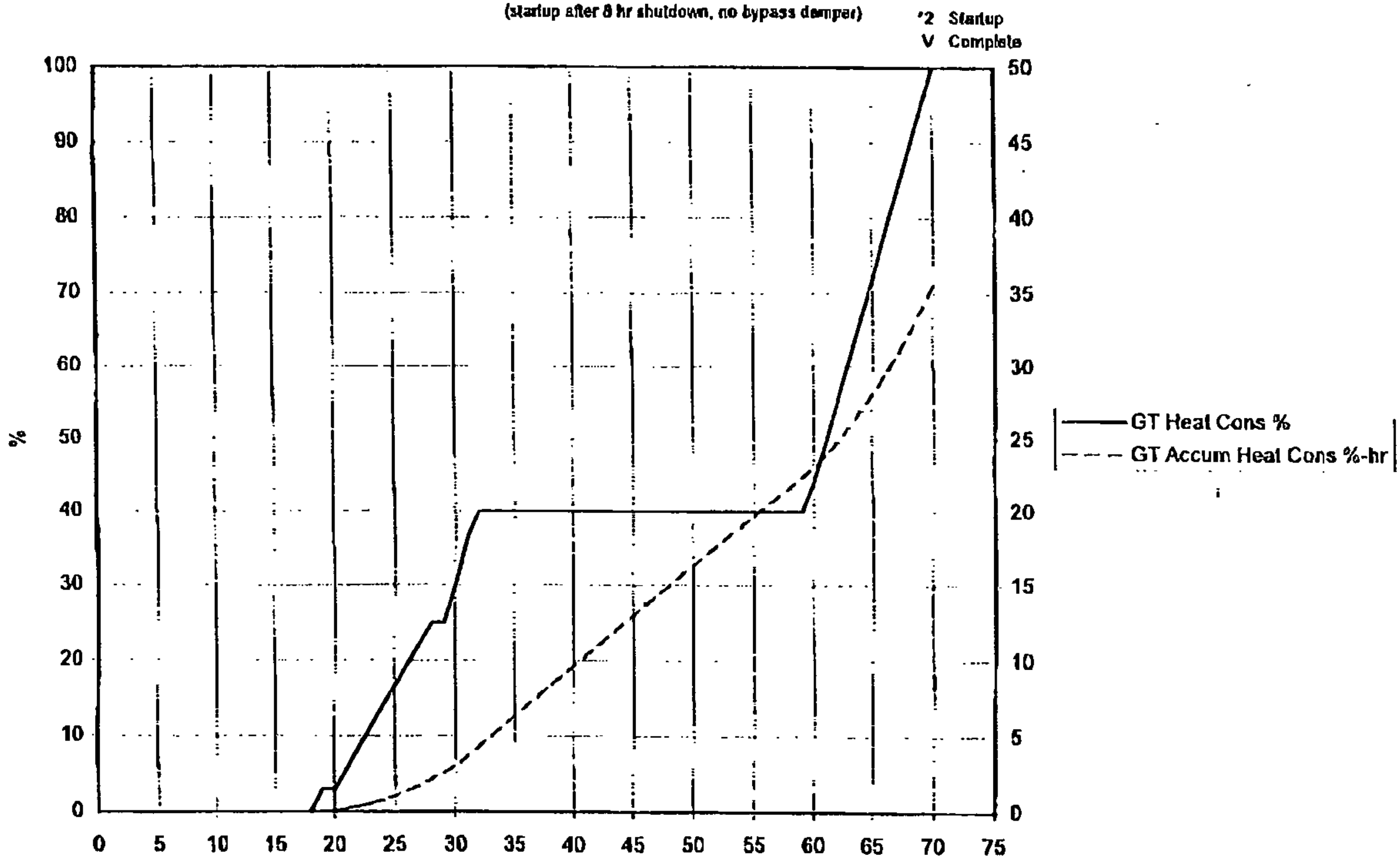


*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

651HA541
GRS 06/15/98

Typical 107FA Hotstart (multishaft)

(startup after 8 hr shutdown, no bypass damper)



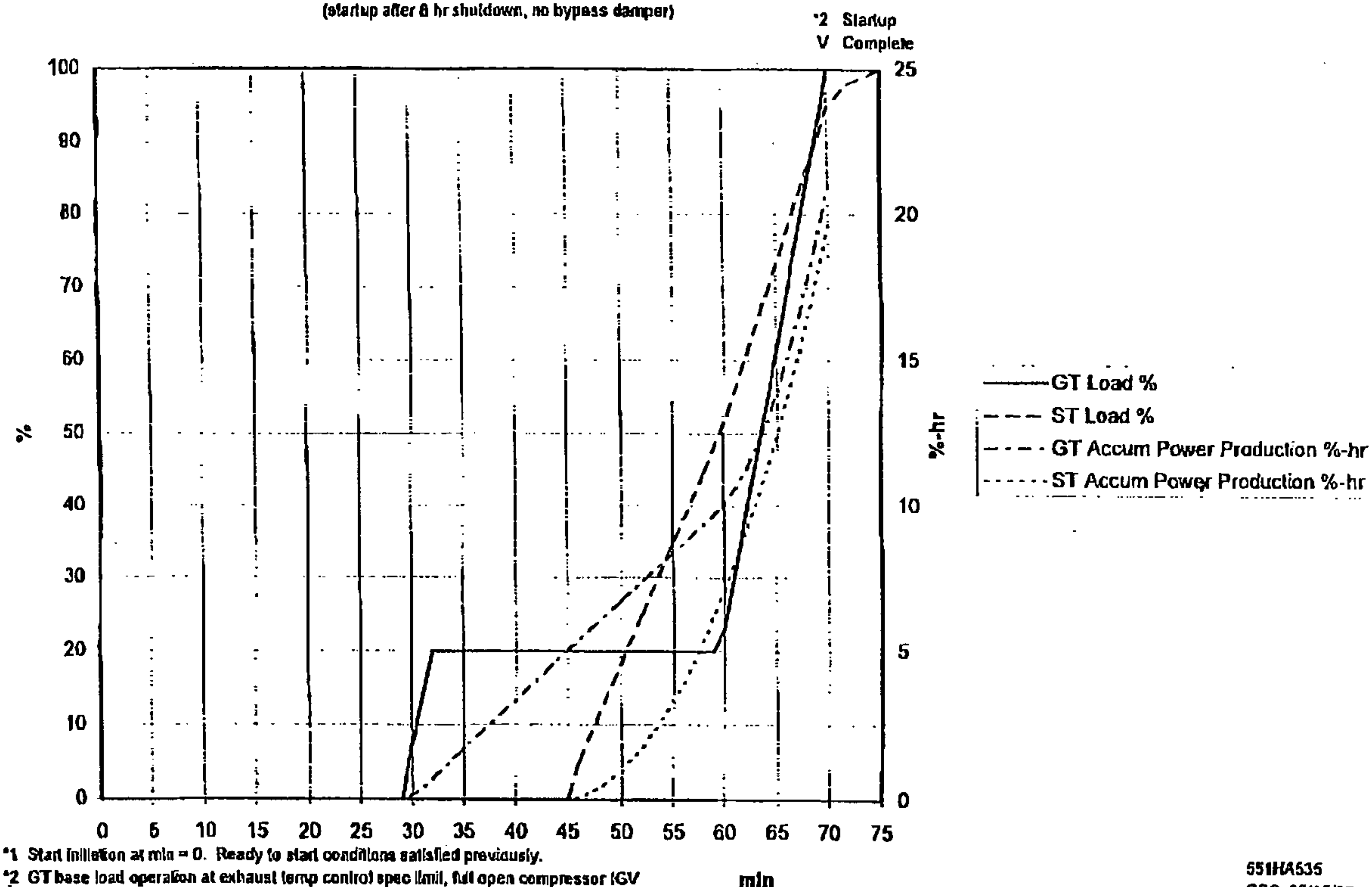
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA534
GRS 06/15/98

Typical 107FA Hotstart (multishaft)

(startup after 8 hr shutdown, no bypass damper)



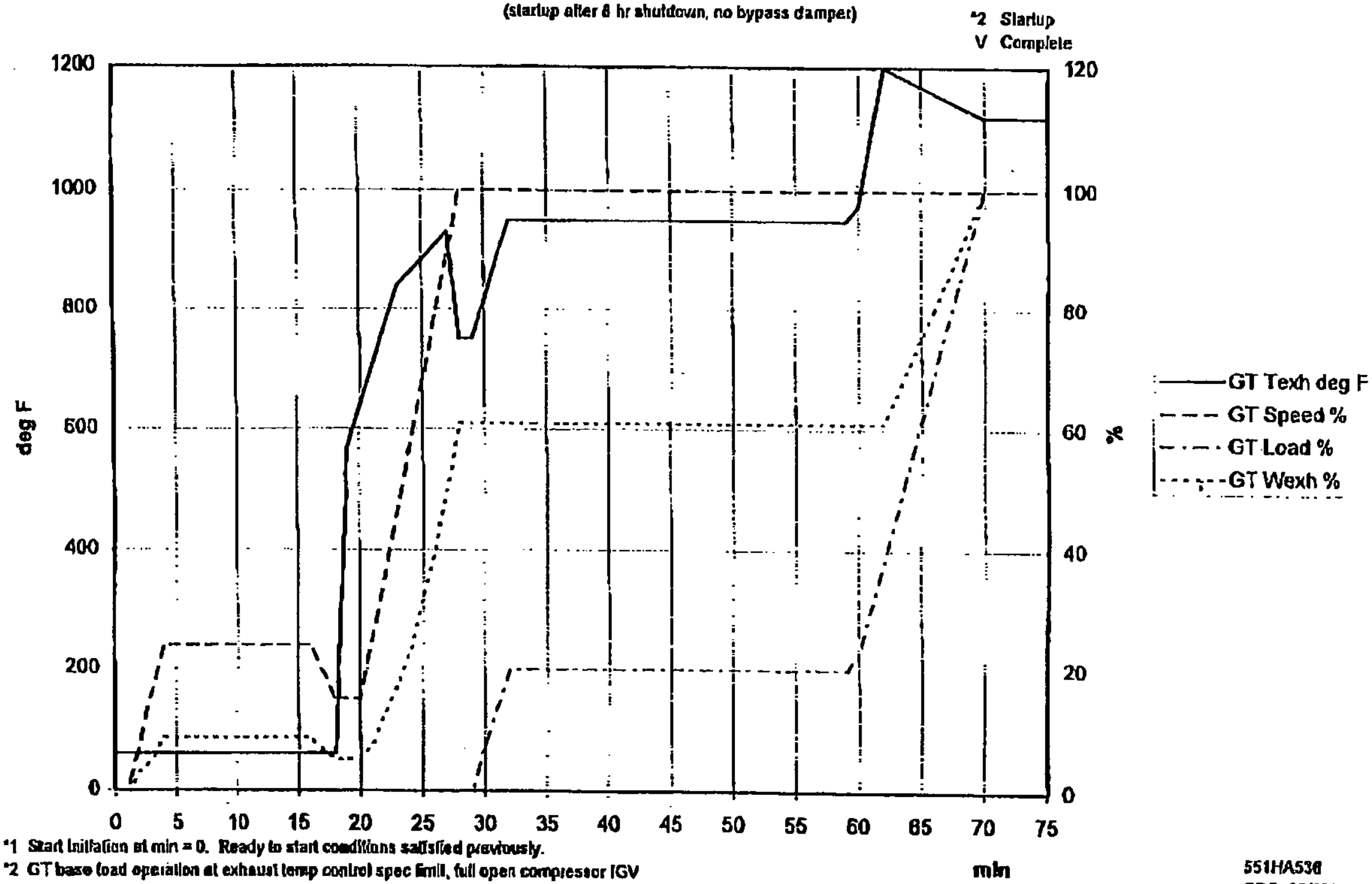
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA535
GRS 06/15/98

Typical 107FA Hotstart (multistart)

(startup after 8 hr shutdown, no bypass damper)



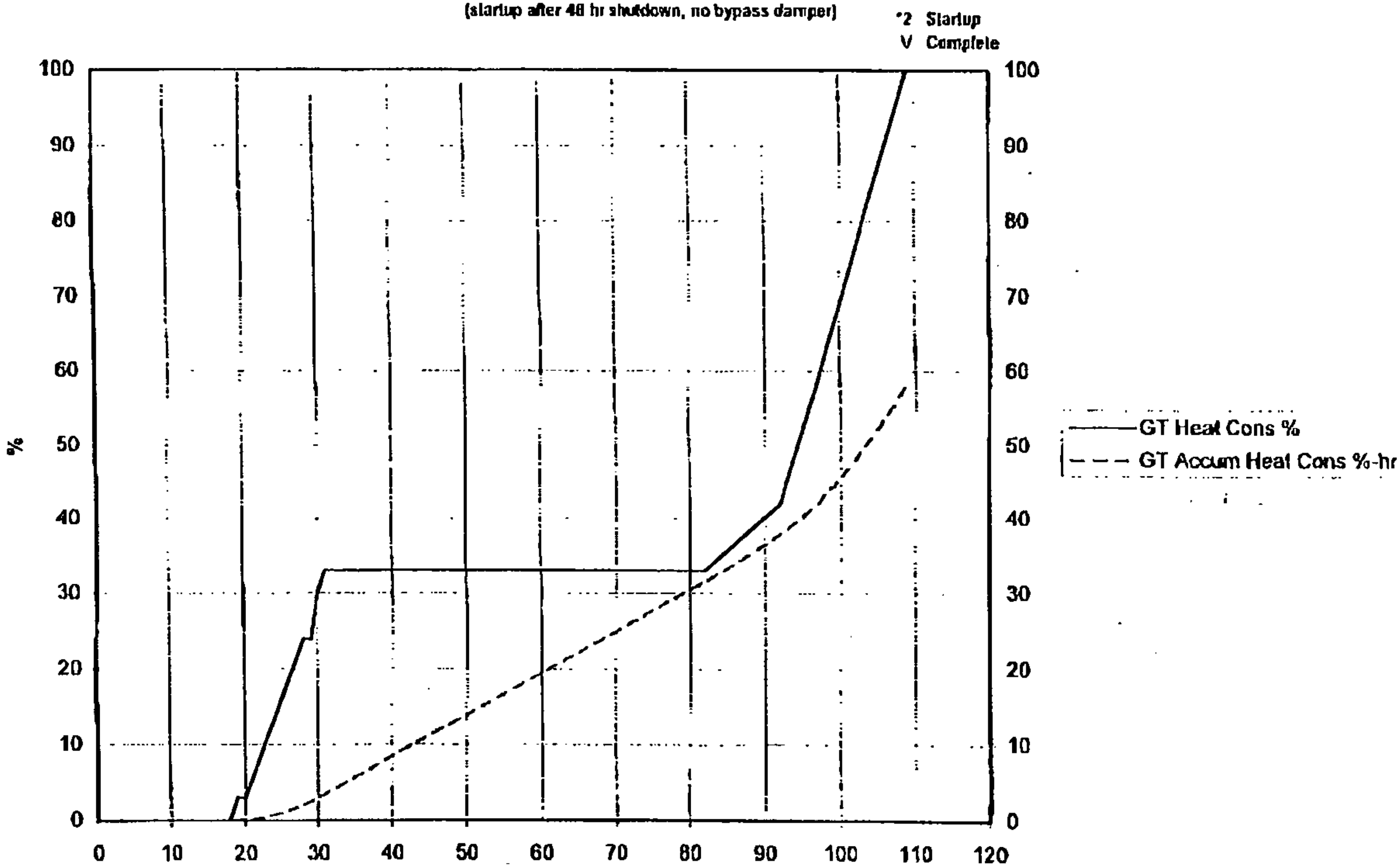
*1 Start Initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA536
GRS 06/15/98

Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)



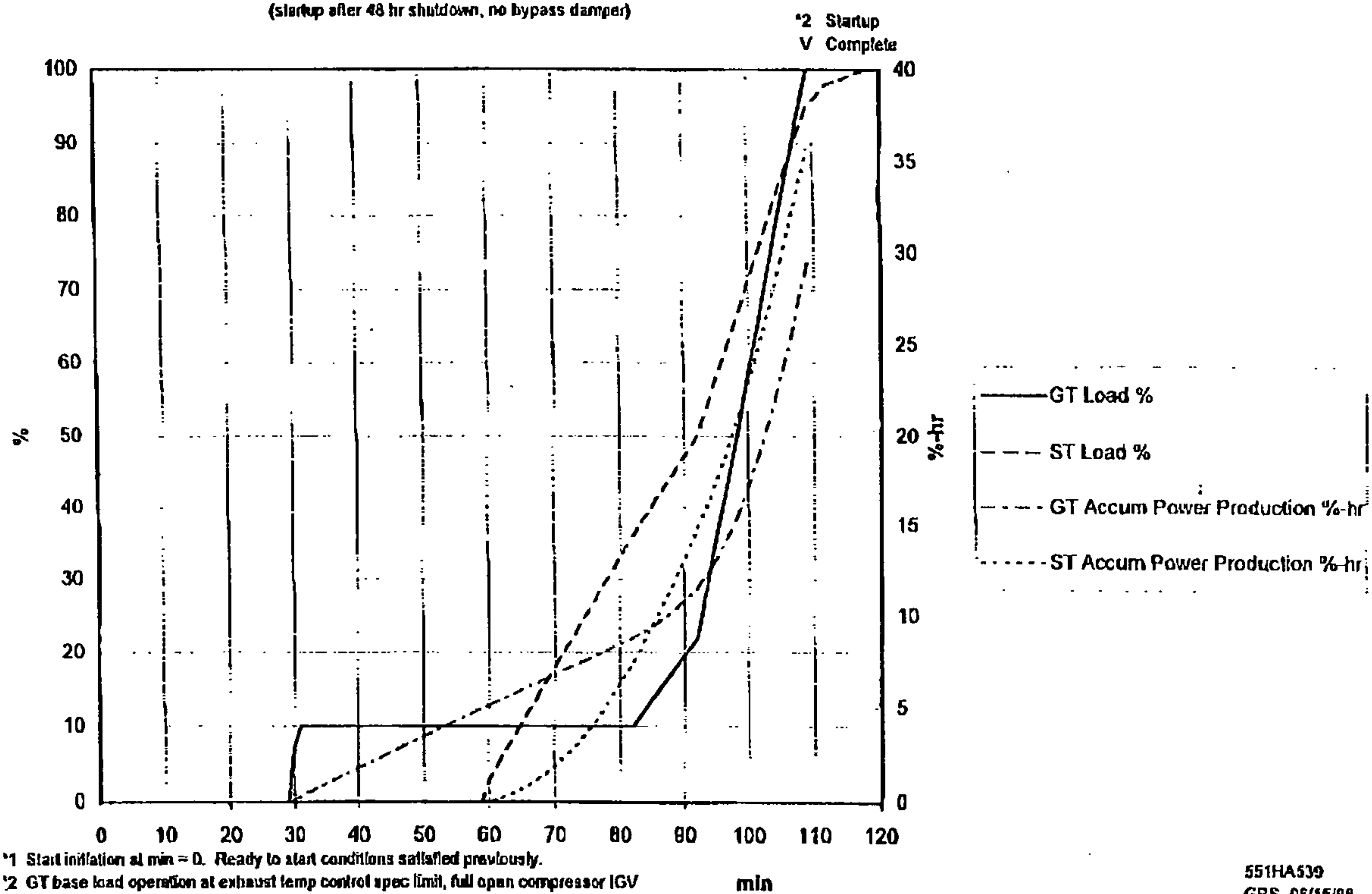
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA538
GRS 06/15/98

Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)

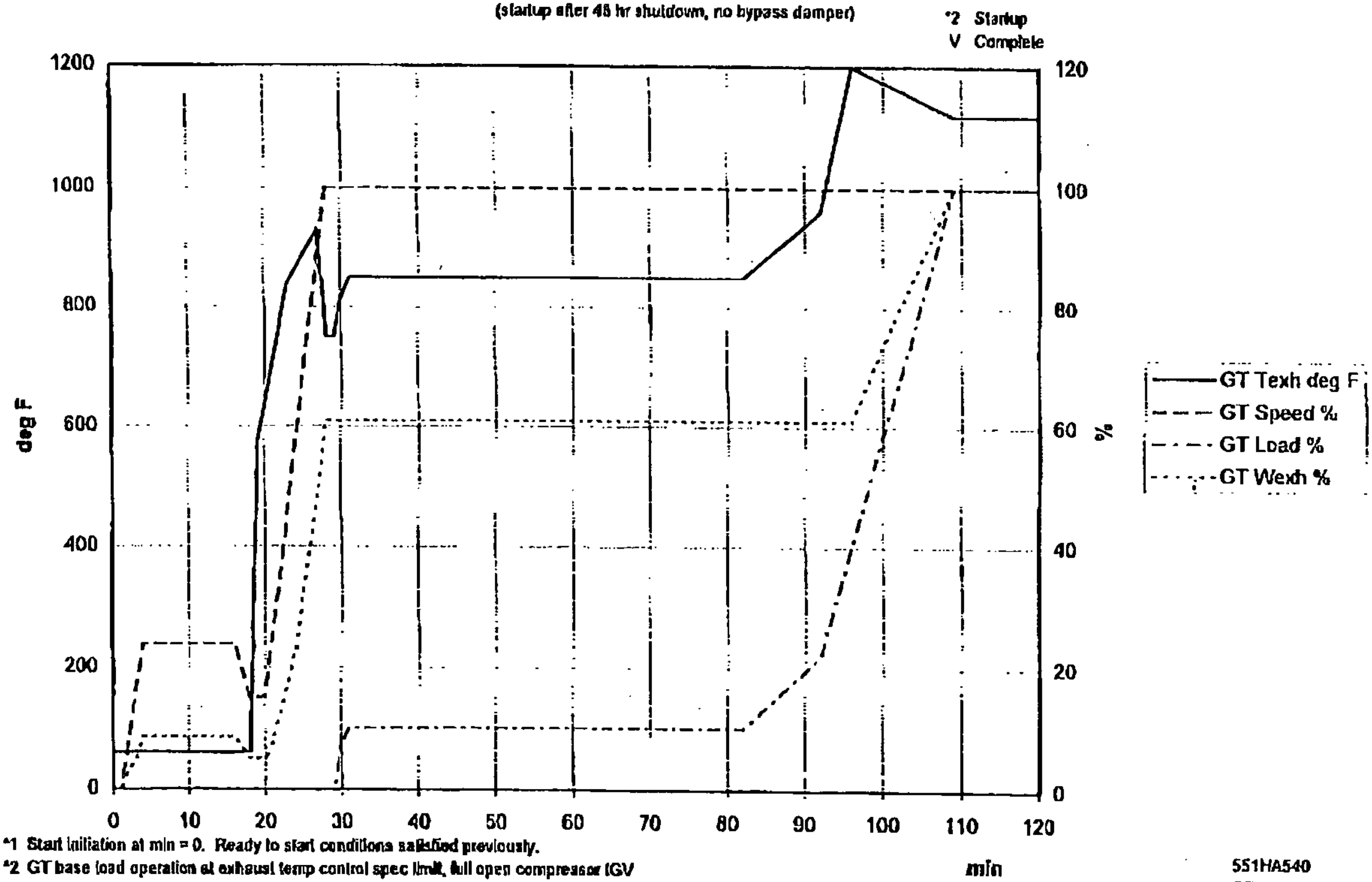


*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA530
GRS 06/15/98

Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)



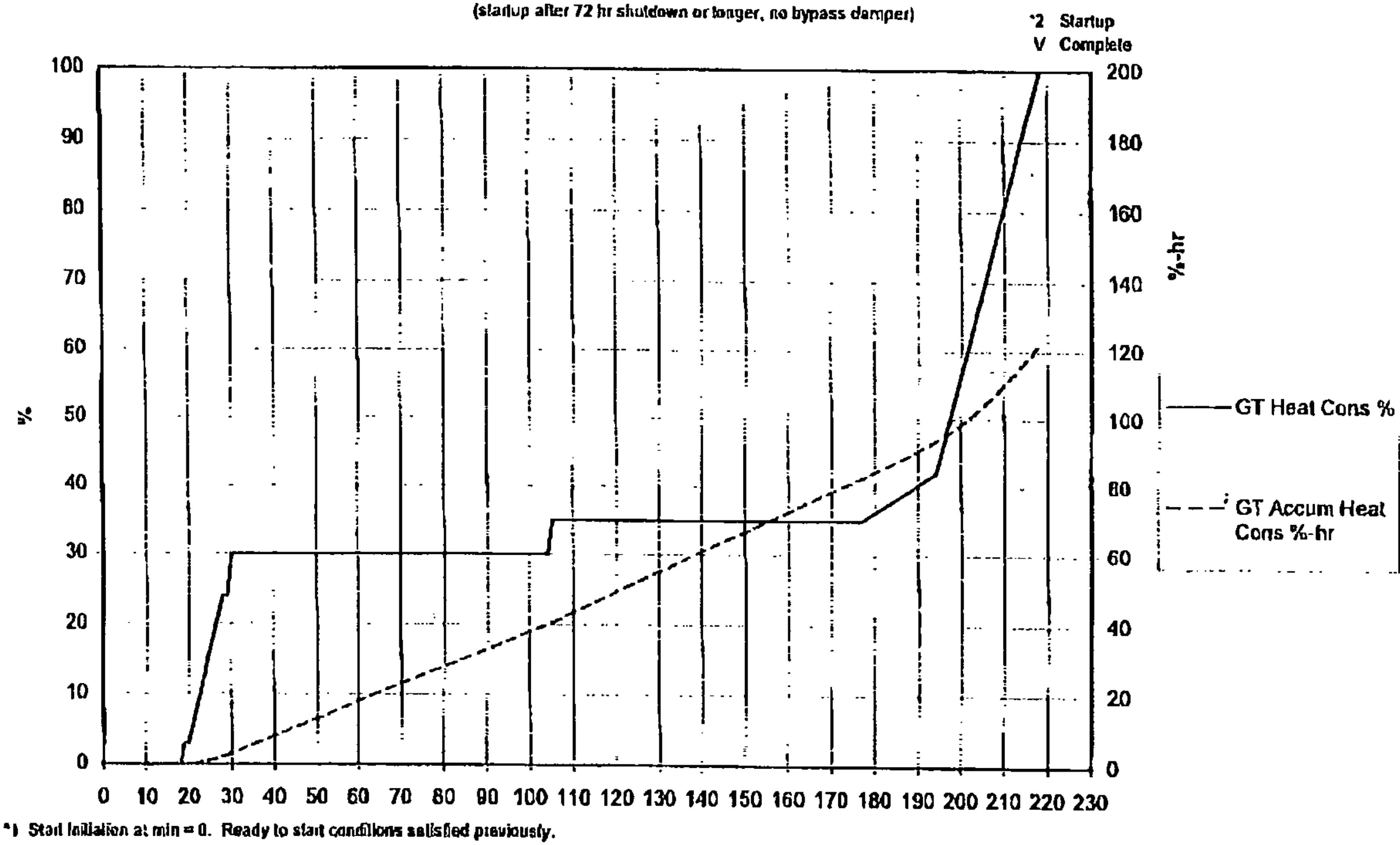
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA540
GRS 06/15/98

Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)



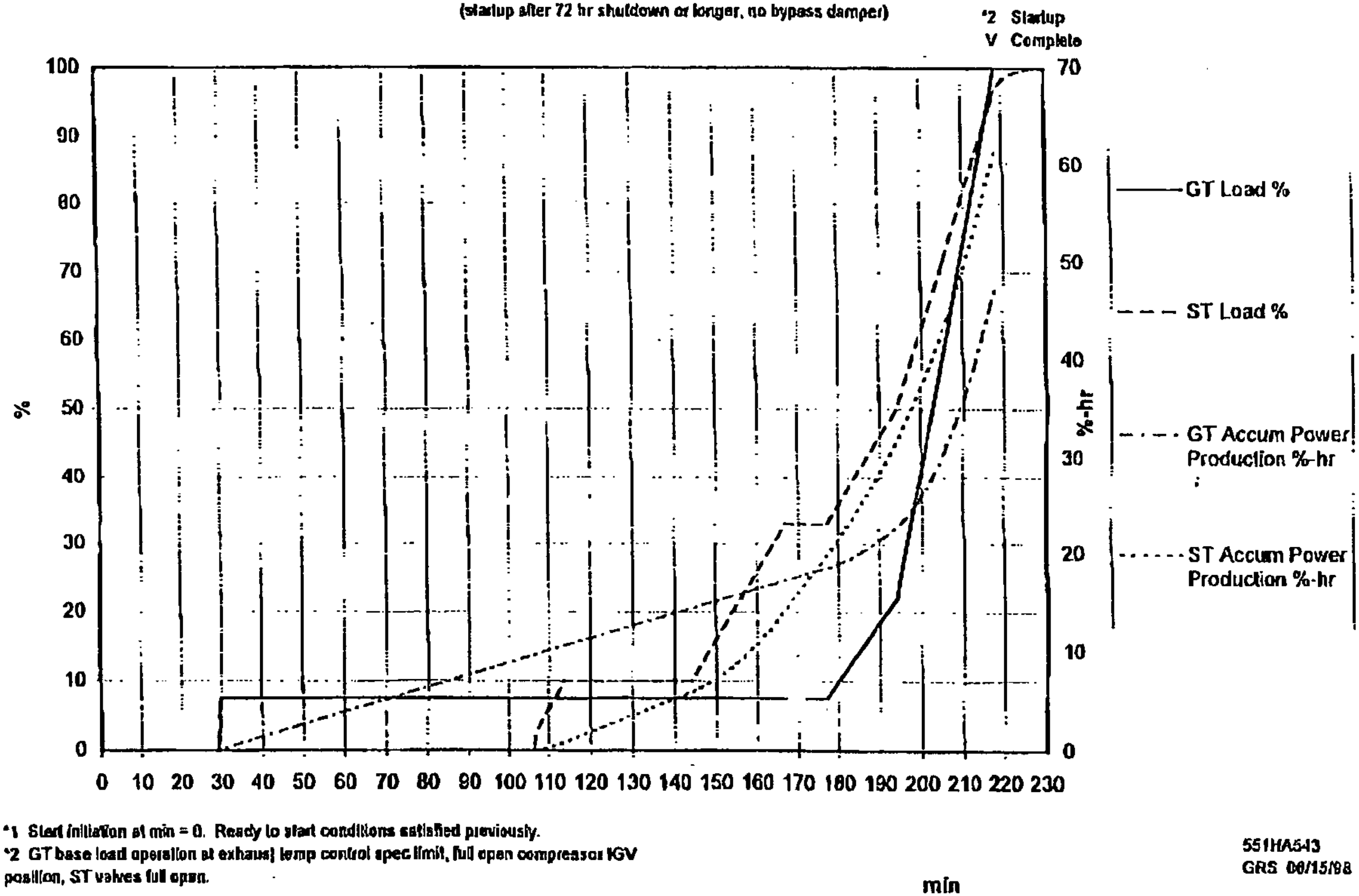
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA542
GRS 06/15/98

Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)

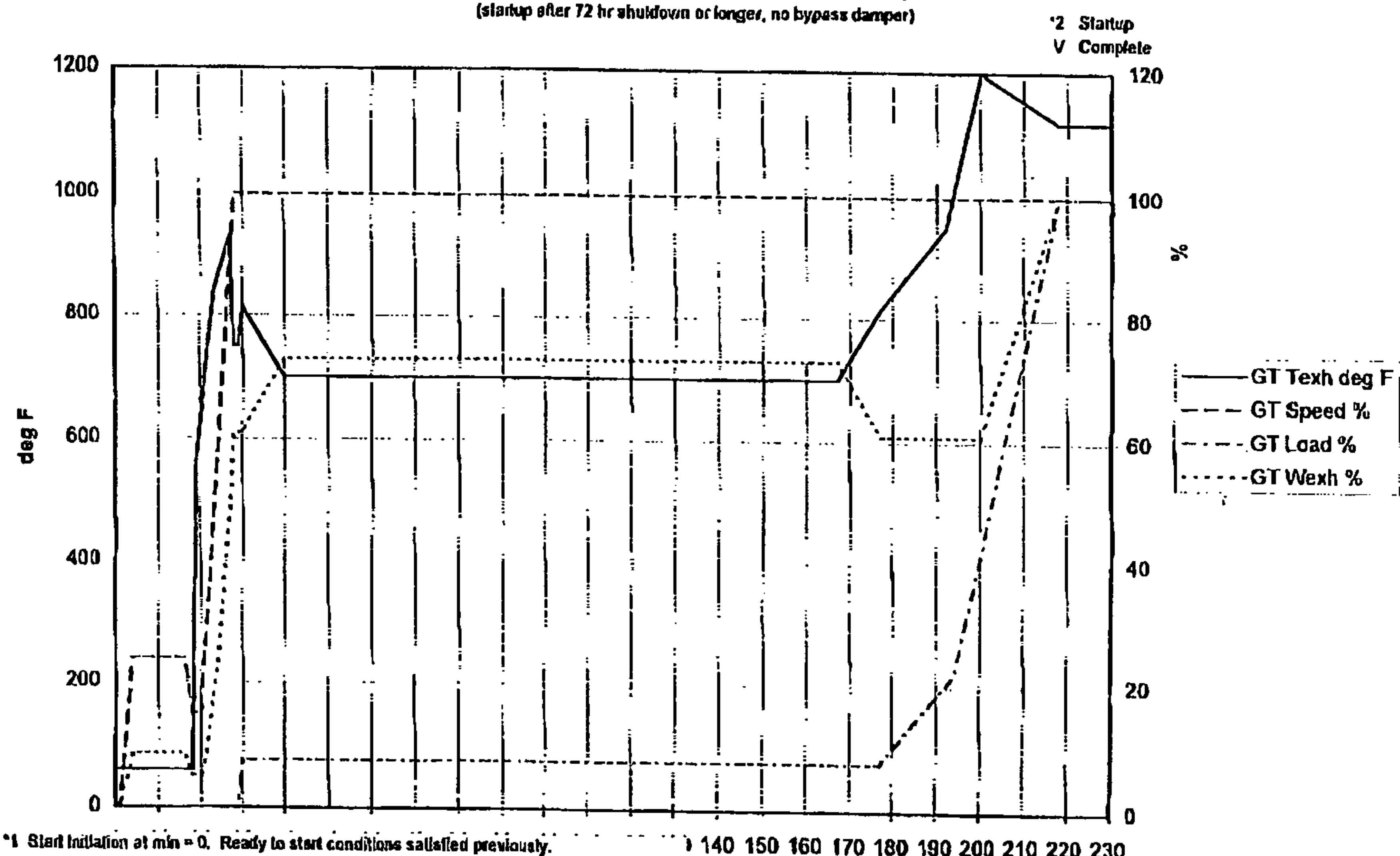


*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA543
GRS 08/15/98

Typical 107FA Coldstart (multishaft)

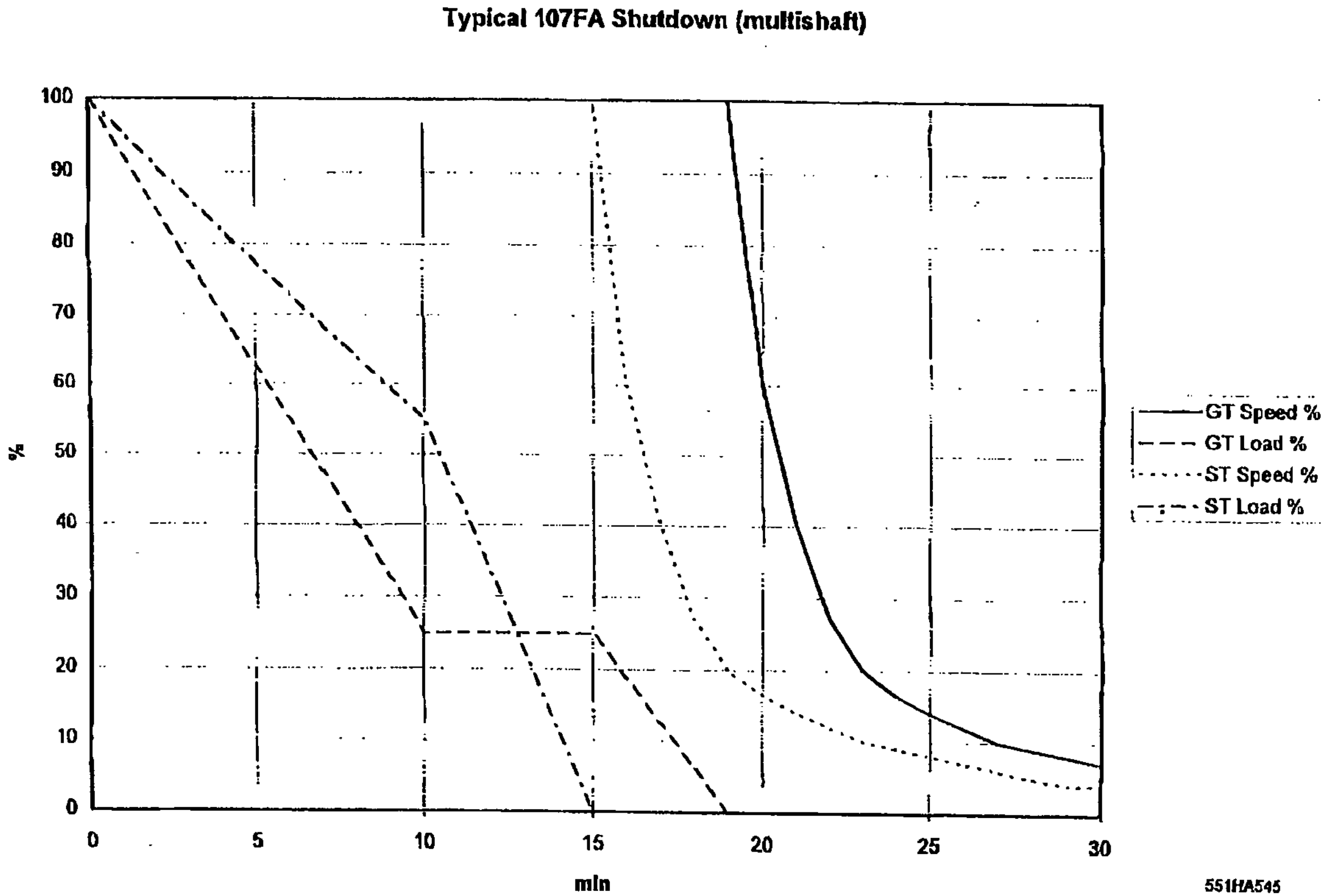
(startup after 72 hr shutdown or longer, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

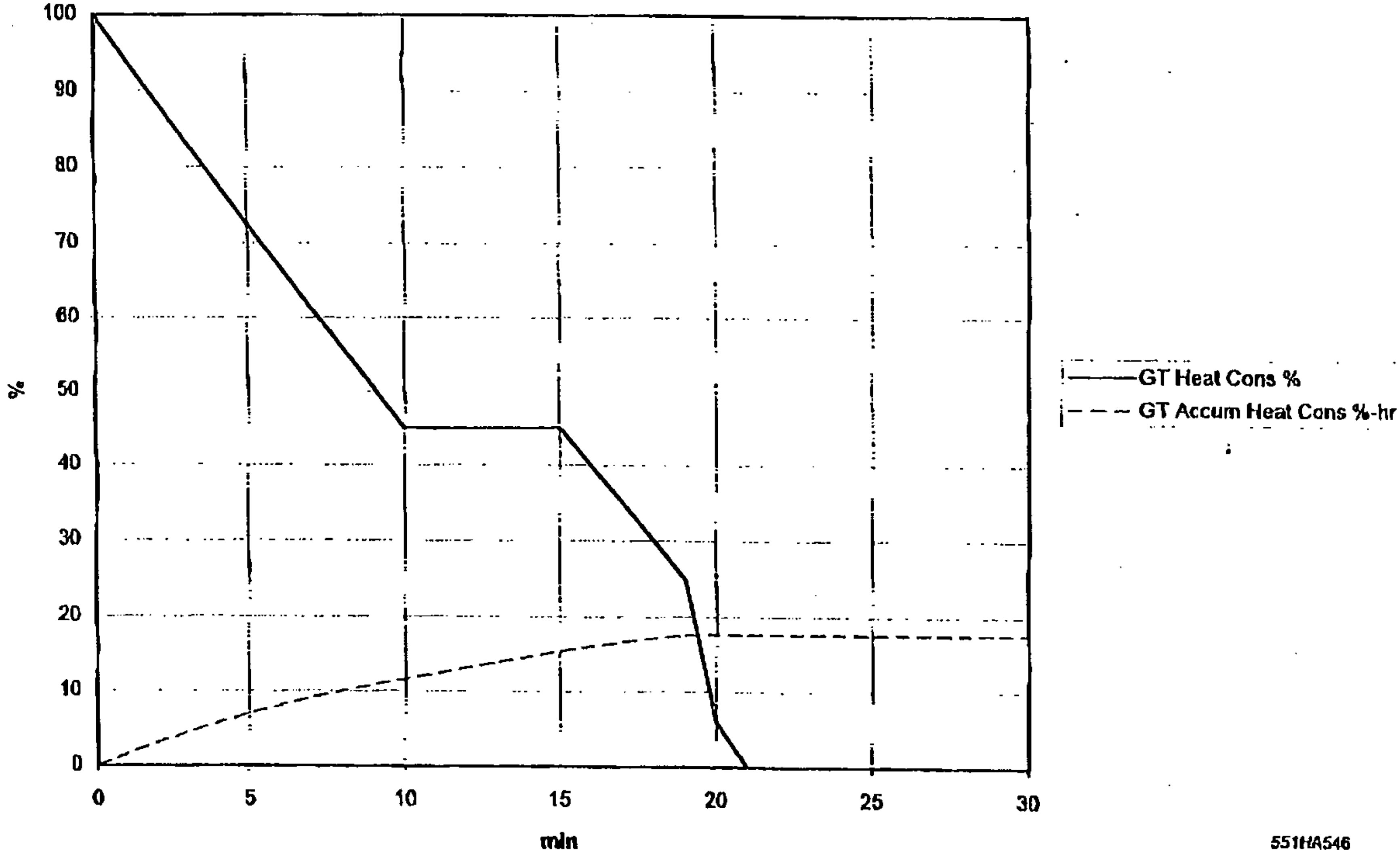
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA544
GRS 06/15/98



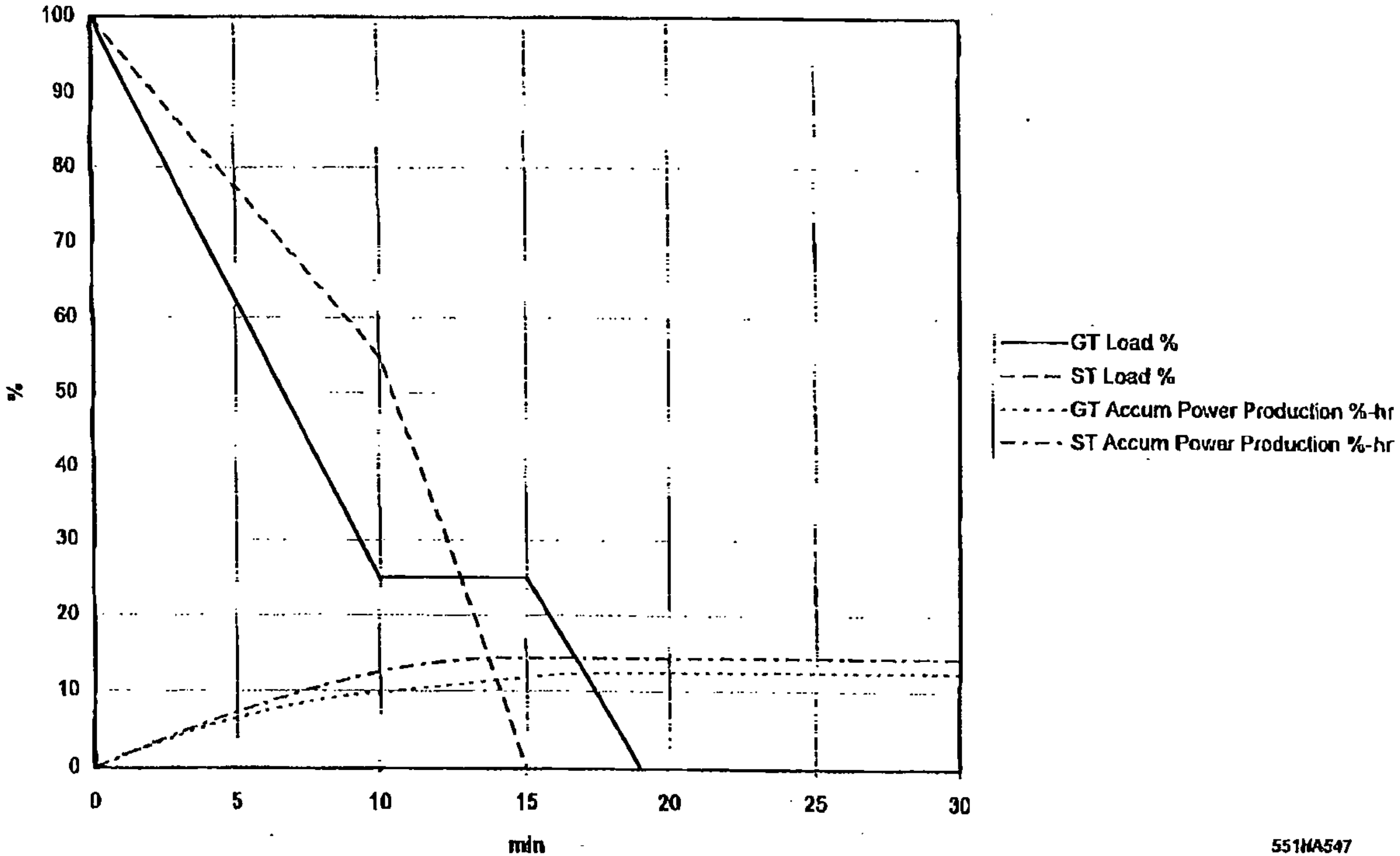
551HA545
GRS 08/15/98

Typical 107FA Shutdown (multishaft)



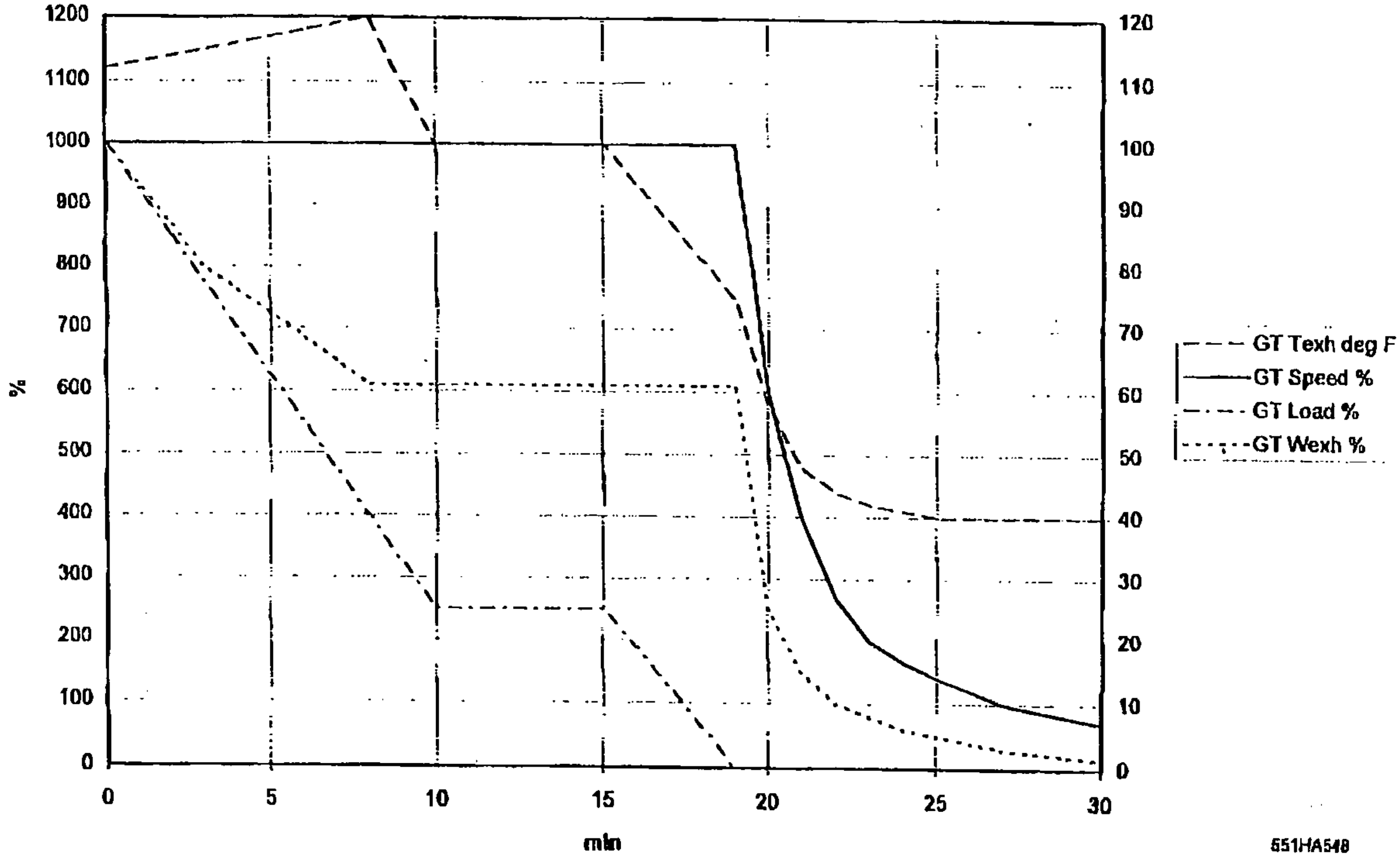
551HA546
GRS 06/15/98

Typical 107FA Shutdown (multishaft)

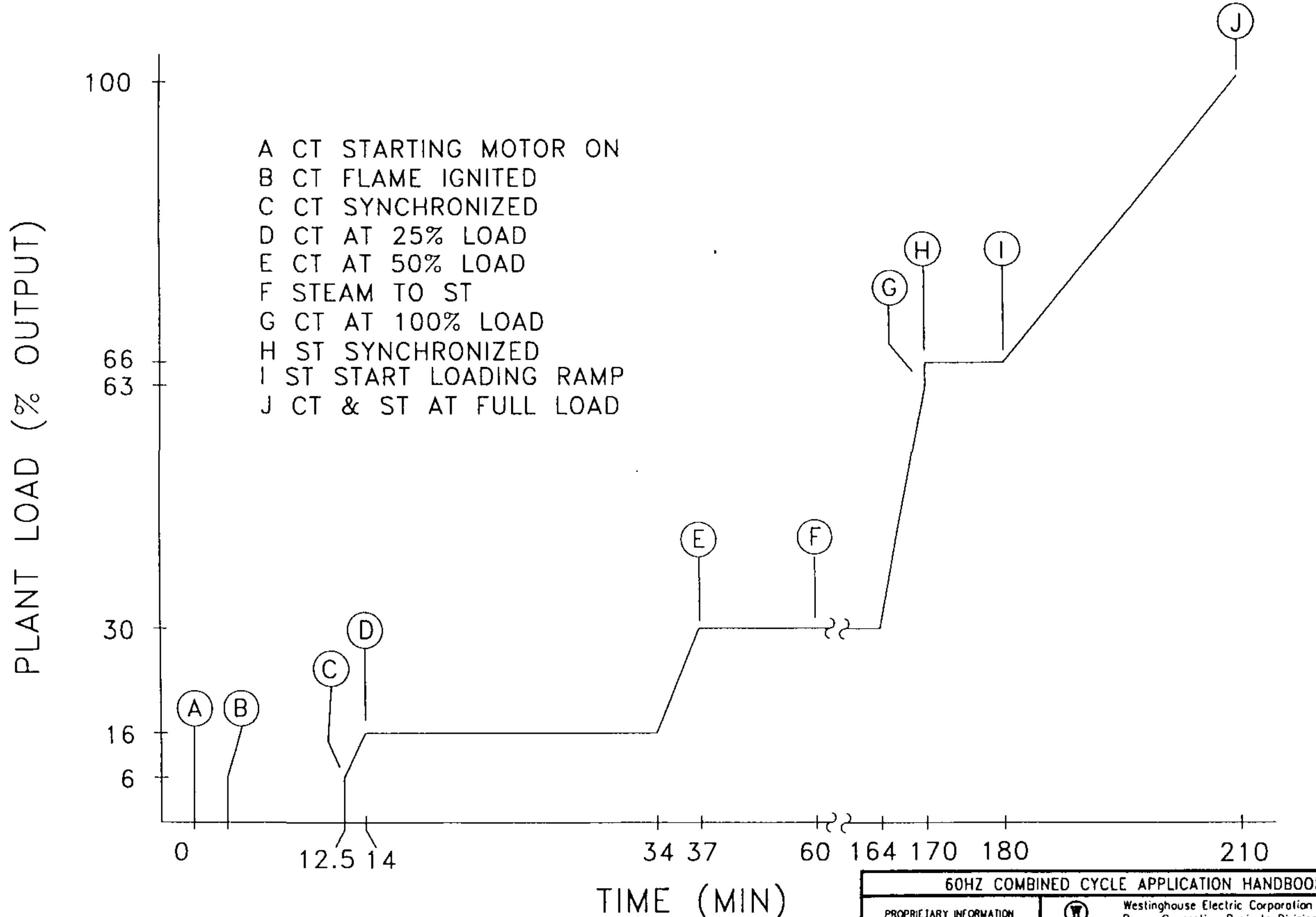


551HA547
GRS 06/15/98

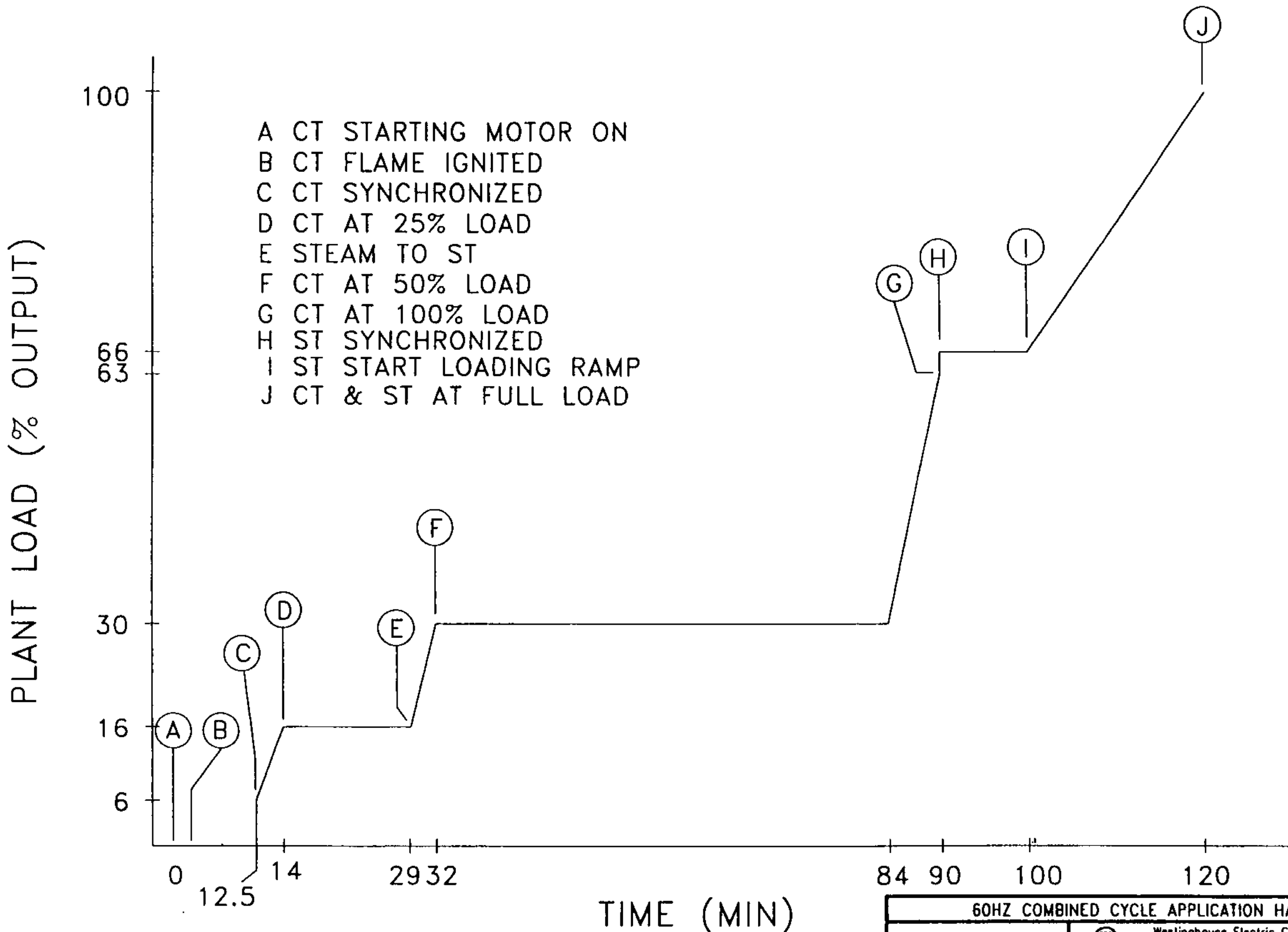
Typical 107FA Shutdown (multishaft)



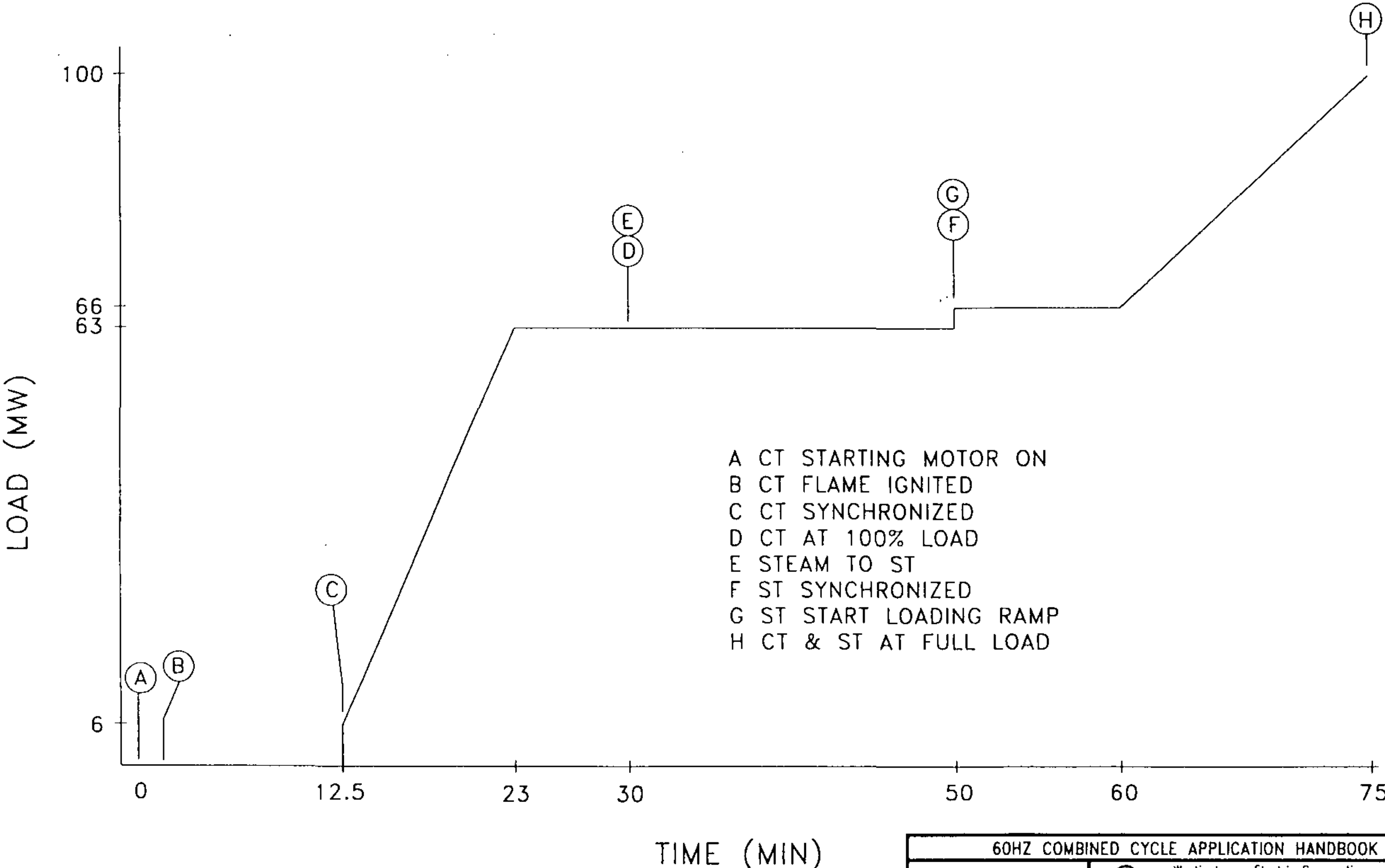
651HA548
GRS 06/15/98



60HZ COMBINED CYCLE APPLICATION HANDBOOK		
PROPRIETARY INFORMATION		Westinghouse Electric Corporation Power Generation Projects Division
DATE 09/15/94	DRAFTER L. MONROE	1X1 COMBINED CYCLE PLANT TYPICAL COLD START LOAD (PROFILE) (72 HOUR SHUTDOWN)
ENGINEER M W ONAITIS MJ		
APPROVED BY m		
CUST. NO. 94506		Drawing No. V1860601	ISSUE 01	Page 1 of 1



60HZ COMBINED CYCLE APPLICATION HANDBOOK	
PROPRIETARY INFORMATION	Westinghouse Electric Corporation Power Generation Projects Division
DATE 09/15/94 — DRAFTER L. MONROE ENGINEER M W ONAITIS APPROVED BY	1X1 COMBINED CYCLE PLANT TYPICAL WARM START LOAD (PROFILE) (48 HOUR SHUTDOWN)



60HZ COMBINED CYCLE APPLICATION HANDBOOK		
PROPRIETARY INFORMATION		Westinghouse Electric Corporation Power Generation Projects Division
DATE 09/15/94	DRAFTER L. MONROE	1X1 COMBINED CYCLE PLANT TYPICAL HOT START LOAD (PROFILE) (8 HOUR SHUTDOWN)
ENGINEER M W ONAITIS MO		
APPROVED BY MK		
CUST NO. 84505		Drawing No. V1860401 ISSUE Page 1 of 1