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IMPACT OF STORM FRONTS ON UTILITIES WITH WECS ARRAYS

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DISCLAIMER

Abstract

The effects of large rapid changes in generation from large arrays of wind turbine generators on the operation of automatic generation control and frequency regulation will be assessed. The maximum change and rates of change of generation from an array of wind turbines due to passage of a thunderstorm front is determined first. The assessment required (1) modeling an array of wind turbines in order to determine power variation for changes in wind speed caused by a storm front; (2) simulation of the model to determine power variation from a worst case coastal farm due to passage of a front; and (3) analysis of the maximum change and rates of change from the portion of the array affected by the front. The theoretical worst case power change and rates of change from a theoretical worst case farm/thunderstorm combination due to passage of the front are also derived based on the formulas derived from the results on the coastal farm. Constraints on the penetration of the portion of an echelon and farm that are affected by the front are derived so that power variation rates will not exceed the response rate capability of a typical system. These penetration constraints would eliminate the occurance of excessive frequency excursions and violations of NAPSIC performance requirements on automatic generation control. The penetration constraints effect on the size of an array and the maximum power variation rates allowed on a particular system are discussed.

FORWARD

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The authors are indebted to Larry M. Smith of the Philadelphia Electric Company for providing the simulation program used in Part II of this study.

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1. INTRODUCTION

The objectives of this research project are to determine

(1) what magnitude and rate of wind velocity change and what magnitude of WECS penetration will cause intolerable operating problems in a typical utility utilizing present operating procedures;

(2) what changes in present operating practice for automatic generation control (AGC), economic dispatch (ED), and unit commitment (UC) may be necessary as WECS penetration increases.

These objectives were stated under Task 1 in our proposal entitled "Development of Wind Electric Application Manual and Simulation of Operating Problems with Wind Turbine Generator Arrays on Interconnected Electric Systems" [1].

The objectives of this study require the development of a model for an array of wind turbine generators (WTG), a long term power system dynamic model, and a simulation program that can be used to test and analyze the performance of the frequency regulation and automatic generation control responses of typical power systems to variations in generated power from such a WTG array due to wind fronts and thunderstorm gust fronts. Therefore, Part I of this task discusses the models and the simulation program used to test and analyze the performance of frequency regulation and automatic generation control responses of typical power systems due to variations in generated power from such a WTG array.

The specific objectives of Part I of this task are:

(1) to justify the use of a lumped inertia power system model that does not represent synchronizing torque oscillations between units;

(2) to justify and describe the generating unit models, the load model, and external system models used in the simulation;

(3) to develop (a) a model of the output power of a single WTG to a thunderstorm gust front and (b) a model of the power out of a wind farm, composed of WTG clusters which are affected by the thunderstorm gust front in the time frame of spinning reserve requirement on the response of automatic generation control;

(4) to justify the use and describe the operation of an automatic generation control-economic dispatch strategy patterned after the one used on the PJM* interconnection, which is used in this simulation program;

(5) provide a data base for this model;

(6) to justify the aggregation of similar generating units that are base loaded, under economic dispatch only, or are under both regulation and economic dispatch. Analysis will be performed to modify the automatic generation control-economic dispatch strategy when similar units performing a particular function are aggregated;

(7) analyze the dynamic performance of the automatic generation control-economic dispatch strategy for aggregated generation to show that it is satisfactory for assessing operating problems due to wind power variation as the penetration of a wind farm increases.

The generator models, the automatic generation control-economic dispatch, strategy and the unit commitments for several operating conditions have been supplied by Philadelphia Electric for the PJM system [2]. Larry Smith of Philadelphia Electric provided invaluable assistance in providing explanation and documentation needed to implement this program and understand the models.

*The simulation program is an adaptation of the model used by the Pennsylvania-Jersey-Maryland (PJM) power pool.

Part II of this study uses the model of an array of wind turbine generators and the simulation program of a model of a typical power system to analyze and test the performance of the frequency regulation and automatic generation controls for worst case power variations produced from worst case wind array configuration for a worst case thunderstorm gust front. The analysis will show that proper constraints on penetration of any wind farm and the penetration of any echelon in the wind farm will permit present frequency regulation and automatic generation controls to adequately respond to worst case power variation from an array of wind turbine generators.

The specific objectives of Part II of this study are

(1) to determine a theoretical worst case farm and thunderstorm gust front based on physical constraints on the size and speed of a thunderstorm gust front and the spinning reserve requirements and response capability on automatic generation control and frequency regulation control strategies. The response of a single WTG including its shutdown and startup sequence for excessive sustained wind speed is simulated and analyzed. The worst case coastal and midwestern plains farm configuration is determined based on the theoretical worst case farm configuration, and the worst case power variation record for each is determined for the worst case thunderstorm front;

(2) to compare the average power variation rates out of these two wind farm configurations with the average response rate capability of a typical power system. The average response rate capability of a typical power system is expressed as a percentage of system capacity and is plotted as a function of the time interval over which this average is calculated. This analysis of the average response rates out of a wind farm and the

average response rate capability indicates the penetration level, of the entire wind farm that can be affected by a single thunderstorm gust front, should be less than the penetration of the largest unit in a typical system. Thus the AGC spinning reserve can assure adequate response to either shutdown or startup of this wind farm. The penetration of any echelon, which is all WTGs that respond to the wind speed on a thunderstorm gust leading edge outflow, is constrained so that the power variation rate will be less than the response rate capability of a typical system. This penetration constraint level varies between 2% and 3% and takes on the lower values if the rate of change of wind speed in the leading edge outflow is high or if the number of WTGs in an area near any particular echelon is also high. The largest capacity system which will not adequately respond to theoretical worst case power variation from an echelon or farm will also be established;

(3) to determine from the simulation the effects of such parameters as

(1) system size (penetration)
(2) Unit Commitment (Morning Pickup, Summer Peak, Evening
(3) Generation Mix (Two Morning Pickup Unit Commitments)
(4) Availability of Bulk Storage Devices

on area control error, frequency, tie line interchange, and regulation-cycling on particular units for a specific worst case wind power variation record from a single wind farm. Specifically, operating problems due to simultaneous load and wind power variations for morning pickup and evening dropoff and due to the response limitation during summer peak is assessed. The changes in response rate capability due to changes in generation mix and cycling problems due to constant changes in wind power on different echelons is investigated. Improvement in response capability and AGC performance when generation mix includes a larger percentage of faster responding units is also assessed.

SUMMARY OF PART I

The final report of Part I of this research project follows in the next three sections. Section 2

(1) justifies and develops the lumped inertia model [2] used in this simulation;

(2) justifies and develops the generating unit model, the external system model, and the load model [2];

(3) develops the models for the local and central dispatch offices that perform automatic generation control and economic dispatch functions.

Section 3 develops the model of an array of WTGs and contains

(1) justification and development of a static nonlinear model of a single WTG under normal operating conditions;

(2) analysis of blade pitch and rotor speed dynamics during the shutdown-startup sequence when wind speed exceeds safe operating limits that can occur during a thunderstorm gust front;

(3) development and justification for a model of an array of wind turbine generators as modeled in (1) and (2).

This development of the array of WTGs or wind farm is based on the assumption that a farm consists of all WTG clusters that experience changes in generation due to a single thunderstorm front in the time interval of spinning reserve requirements on the response of the automatic generation control.

Section 4 contains

(1) the rationale for aggregating similar generating units (hydro, coal fired drum, oil fired drum, subcritical once through, supercritical once through, gas turbine, boiling water reactor) performing the same function (economic dispatch, regulation, base loaded);

(2) a discussion of the assumptions required for this aggregation and a justification for each of the aggregated units to be included in the simulation;

(3) a discussion of the aggregation procedure which includes

  (a) the modification of the regulation - economic dispatch strategy required for aggregated units with aggregated cost curves;

  (b) the determination of cost curves for aggregated units given cost curves for typical units of each kind retained in the simulation.

Section 5 contains an analysis of the dynamic performance of this automatic generation - economic dispatch control strategy to determine if it meets typical spinning reserve requirements and NAPSIC response requirements [2] and thus, the AGC-ED for the aggregated generating units is appropriate to study the operating problems that result due to wind power variations when wind penetration levels increase.

2. POWER SYSTEM DYNAMIC MODEL DEVELOPMENT

A very thorough examination of alternative models and model structures was undertaken in order to determine which model type would best fit the objectives of this research. Two basic model structures were identified:

(1) a lumped inertia model [2,3] with a one second integration step size that eliminated all synchronizing torque oscillations between machines. The generation component models were selected to reflect the response of a unit to major changes in load demand and thus included boiler feedwater and fuel dynamics;

(2) dynamic models that included an explicit representation of the electrical network and permitted the representation of synchronizing torque oscillations. Generation component models sometimes did not include feedwater, fuel, and boiler models [4,5].

It was determined that the model should use a lumped inertia representation and detailed model of longer term generator dynamics [2] and thus should ignore synchronizing oscillations and generator dynamic with time constants of less than one second because

(1) other DOE contracts were investigating the dynamic and stability problems associated with wind turbine generation and the effects of wind turbine generation dynamics on the neighboring generators [6];

(2) the stated objectives were to evaluate the performance of automatic generation control, economic dispatch, and unit commitment as WECS penetration increased. Since automatic generation control, economic dispatch, and unit commitment are slow responding power system control strategies and thus should not be affected by:

(i) synchronizing torque oscillations which range from 0.5 to 2.5 hz.

(ii) the dynamics of single or multiple wind turbine generators connected to the system at a particular bus in normal operation because these dynamics for single or multiple generators were shown to have a dominant mode at or above 0.6 hz [7].

(iii) the interaction of these fast WTG dynamics with generation electrically close to the WTG because the effects would mainly be on governor action in a frequency range above 0.1 hz. The effect of change in wind array generation due to thunderstorm gust fronts on the frequency regulation of nuclear and steam turbine generation will be investigated. (It should be noted that this interaction of WTG responses with governors of neighboring generators is a major concern but is not within the scope of this research. It is being considered by other DOE contractors.)

(3) the performance of the automatic generation control economic dispatch, and unit commitment strategies must be evaluated over periods as long as several hours which would be very expensive to simulate if the non-lumped inertia models were used.

The lumped inertia model with a one second integration step was thus chosen as the fundamental building block for the power system model to be developed. Moreover, drum and once through steam turbine, hydro turbine, gas turbine, and boiling water reactor generator models were chosen based on the requirement that they be able to accurately represent the response to large changes in load demand and that they be compatible with a one second integration step size. This latter requirement forced modification or elimination of all dynamics with time constants below one second. The generating component models used are those developed by Philadelphia Electric [2] for the PJM interconnection.

Since the automatic generation control-economic dispatch strategy used by PJM is typical, is well-documented, and since it was utilized with the basic generation component models to be used in this model, the automatic generation control-economic dispatch strategy to be used in this model will be patterned after that used in the PJM interconnection. A unit commitment strategy and associated data for the automatic control-economic dispatch for that unit commitment has been supplied by Philadelphia Electric for four operating conditions on its system. It should be noted that even though much of the data for our model is provided by Philadelphia Electric and the automatic generation control-economic dispatch strategy is patterned after PJM's, the results in our study will not be identical to that from the Philadelphia Electric model and will not reflect the performance on the PJM system because

(1) each of the generators that are similar (oil fired drum, coal fired drum, once through, boiling water reactor, gas turbine, hydro turbine) that perform the same function (regulation, economic dispatch, base loaded) in the PJM model are aggregated into a single generator of that type performing that function in the model being developed. The PJM model [2] represents each generation in the system separately;

(2) only a single load dispatch center will be used rather than individual local load dispatch offices for each company in PJM. This use of a single local dispatch office would not affect the results if all local dispatch offices were identical which is not true in the PJM system. The PJM model [2] represents each of these local dispatch offices separately;

(3) the PJM automatic generation control-economic dispatch strategy was modified to handle
(1) aggregated generator models for each generator type performing the same function and

(2) a single local dispatch office. The performance of the regulation and economic dispatch using aggregated units and a single dispatch center can only approximate the collective response of the corresponding individual units controlled through distinct local dispatch offices.

The particular component models for this power system model will not be developed based on the following logic. The lumped inertia model will be developed first since it is the basic building block for the power system model. The models of particular generation components; including drum, once through, boiling water reactor, gas turbine, and hydro turbine generators will then be discussed. Finally, a model of the external system and a load model will be discussed to complete the discussion of the dynamic model of the power system.

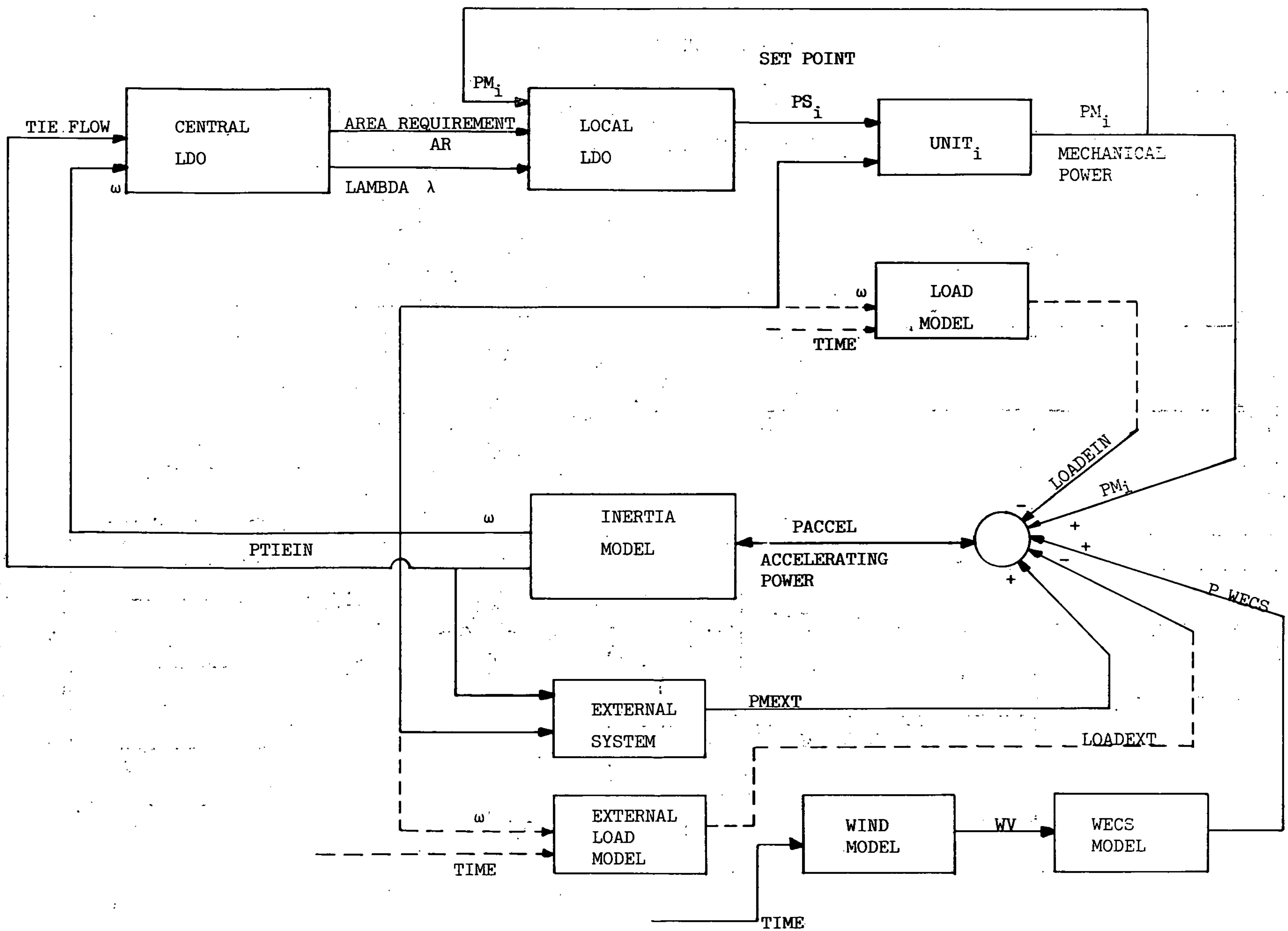
Functional block diagrams of the central and local dispatch offices will then be discussed in terms of the particular operations used to perform the regulation and economic dispatch functions. The central load dispatch office determined the filtered area control error, AR, and marginal cost signal, LAMBDA, from the system frequency OMEGA, and tie line power signals, PTIEIN, determined in the lumped inertia model. The local dispatch office model used AR and LAMBDA signals from the central dispatch office, and the mechanical power output of each generation unit, PM_i, to determine the setpoint PS_i for generating units i=1,2,...N under its control. A block diagram of the power system model with the automatic generation control-economic dispatch functions is shown in Figure 1.

The description of the model that follows is not intended as a detailed description of the FORTRAN code which was written to simulate the particular models.

2.1 Inertia Model

The lumped inertia model is not only the basic building of this power system model but also the block to which almost every other component model is connected as shown in Figure 1. The lumped inertia model, shown in Figure 2, accepts the internal system load. LODEIN, from the load model; the prime

Fig. 1 BLOCK DIAGRAM OF SIMULATION MODEL



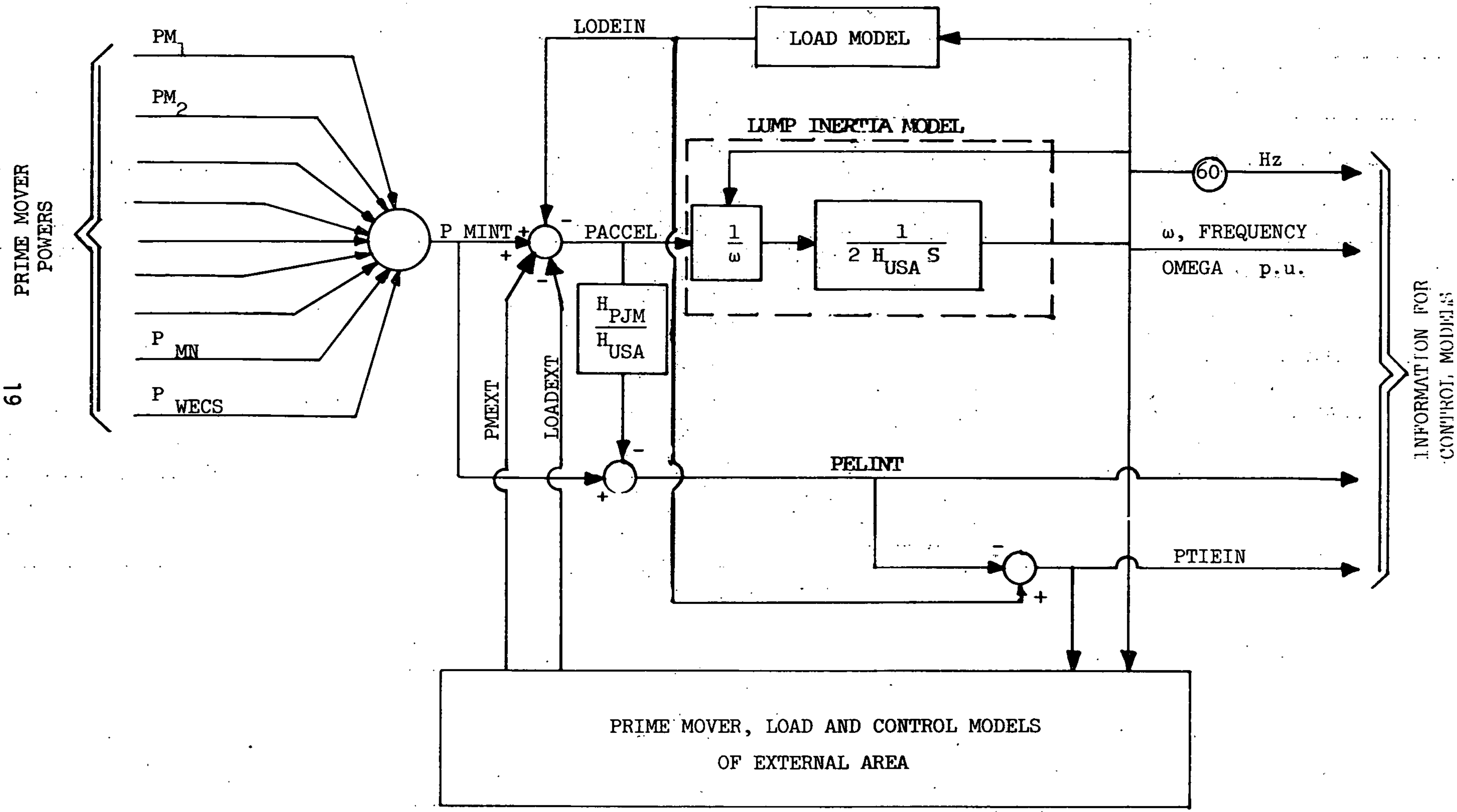


FIG. 2 LUMPED INERTIA AND INTERTIE MODEL

mover power, PM_i, from each generator component model; the wind array power, P_{WECS}, from the wind array model; and the external system prime mover power, PMEXT, and external load power, LOADEXT, from the external system model. This inertia model then computes system frequency, OMEGA, and tie line flow, PTIEIN, between the internal and external system models.

The system frequency OMEGA or ω is computed from

$$\omega(t) = \frac{1}{2H_{USA}} \int (T_M - T_e)\,dt$$

where

H_{USA} - rotary inertia of the entire system

$T_M - T_e$ - accelerating torque = prime mover torque - electrical load torque

Since the model is a power model and not a torque model, the accelerating torque is

$$T_M - T_e = \frac{\text{PACCEL}}{\text{OMEGA}} = \frac{\text{PMINT+PMEXT-LODEIN-LOADEXT}}{\text{OMEGA}}$$

After PACCEL/OMEGA is formed, it is divided by $2H_{USA}$ to form the per unit angular acceleration which is then integrated to form the per unit angular velocity OMEGA.

The electrical power, PELINT, is the internal system prime mover power minus a percentage of the acceleration power needed to accelerate internal inertia.

$$\text{PELINT} = \text{PMINT} - \frac{\text{HINT}}{\text{HUSA}}\ \text{PACCEL}$$

The tie line power into the internal system is

$$\text{PTIEIN} = \text{LODEIN} - \text{PELINT}$$

The generator component models, which produce the prime mover power PM_i for the inertia model from the power setpoint PS_i from the local dispatch office, OMEGA from the inertia model, and the scheduled frequency CSKEDF/60 for the power system in per unit are now developed. It is assumed that the inertias of each generating unit including the wind array model is lumped and included in HINT. Some of the discussion and the data for these generating component models is taken from [2].

2.2 Gas Turbine Model

The block diagram of a gas turbine generator model is shown in Figure 3. The simplicity of the model is based on the following assumptions

1) Reasonable limits on loading rates will be used in the local dispatch office models where governor speed changer position is determined.

2) It is used with computer time simulation steps of 1 to 2 seconds.

3) The dynamics of the exhaust temperature limits are approximated by an instantaneous limit determined by ambient temperature conditions.

The exhaust temperature limiter dynamics are dominated by the thermal time constant of the exhaust thermocouple, which is about 2 to 3 seconds. This thermocouple time constant is so close to the integration step size that it is represented by a computer delay of 1 second. If the integration step was not 1 to 2 seconds, this model would have to be altered. It is expected that limits on the governor speed changer position will prevent full loading of the unit in the one second time step. A list of the variables is given below:

TABLE I

Speed Regulation $(\frac{CAP}{R})$:	$\frac{\text{MW Rating}}{.05}$
Exhaust Temperature Power Limit (MW at 295°F; CYTO2)	

$$CYTO2 = 1.23-(\frac{.23}{59})*(\text{Ambient Temp})*(\text{MW Rating})$$

for $0 \leq \text{Temp} \leq 120°F$

Deadband, MW (CDBYT)	1 MW
Computer Time Delay	1 sec.

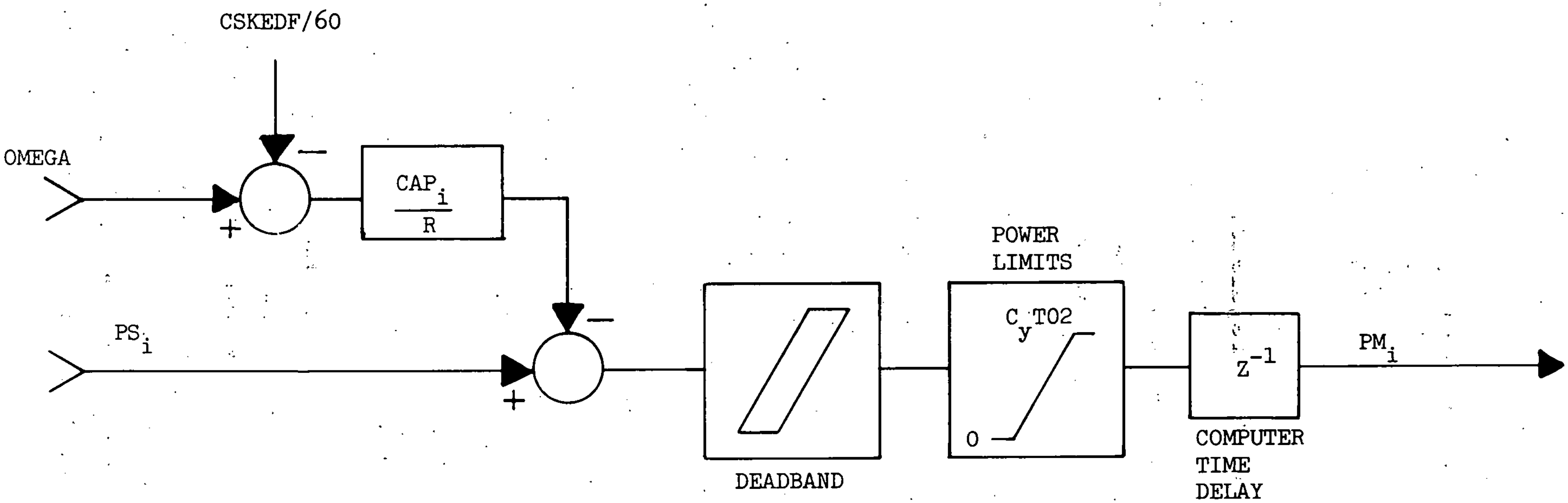


FIG. 3 GAS TURBINE MODEL

2.3 Hydro Turbine Model

The following discussion of the hydro turbine generator model and data is also taken directly from [2]. A block diagram of a typical hydro turbine generator is shown in Figure 4. This hydro turbine generator model can represent either high head-pumped storage unit or low-head run of river units.

The model consists of a regulator, governor and gate dynamics, and turbine dynamics. The model represents a governor with transient droop compensation. If the transient droop were not to be included then the ratio R/r(CYPO2) would be set to 1 and T_r may be arbitrarily chosen. The governor and gate dynamics are further illustrated in Figure 5. This approximates the gate servo-loop with rate and position limits and proportional and derivative feedback action. The feedback gains establish the steady state regulation and transient droop and its washout time.

The servo time constant of the gate is about one second or less and is masked by the temporary droop effect. The model does not include water column or surge tank effects since these are short-term characteristics when compared to the integration step. In order that the model will be valid for both high head and low head hydro generation, a Z form model was used for the turbine simulation, as shown in Figure 6.

The regulator, shown in Figure 4, consists of a gain, integrator, and rate and generation limits

$$-\mathrm{CYPO5} \le \mathrm{UCE}_i \le \mathrm{CPYO5}$$

$$\mathrm{CYPO7} \le \mathrm{PS}_i \le \mathrm{CYPO6}$$

The regulator is not included on base loaded hydro units but is required on hydro units used for regulation. The actual regulator is included in the local dispatch office model but is included here only to indicate that it exists for hydro units used for regulation.

Test data was obtained for the Philadelphia Electric Company's Conowingo Station Unit No. 7. The model data given in

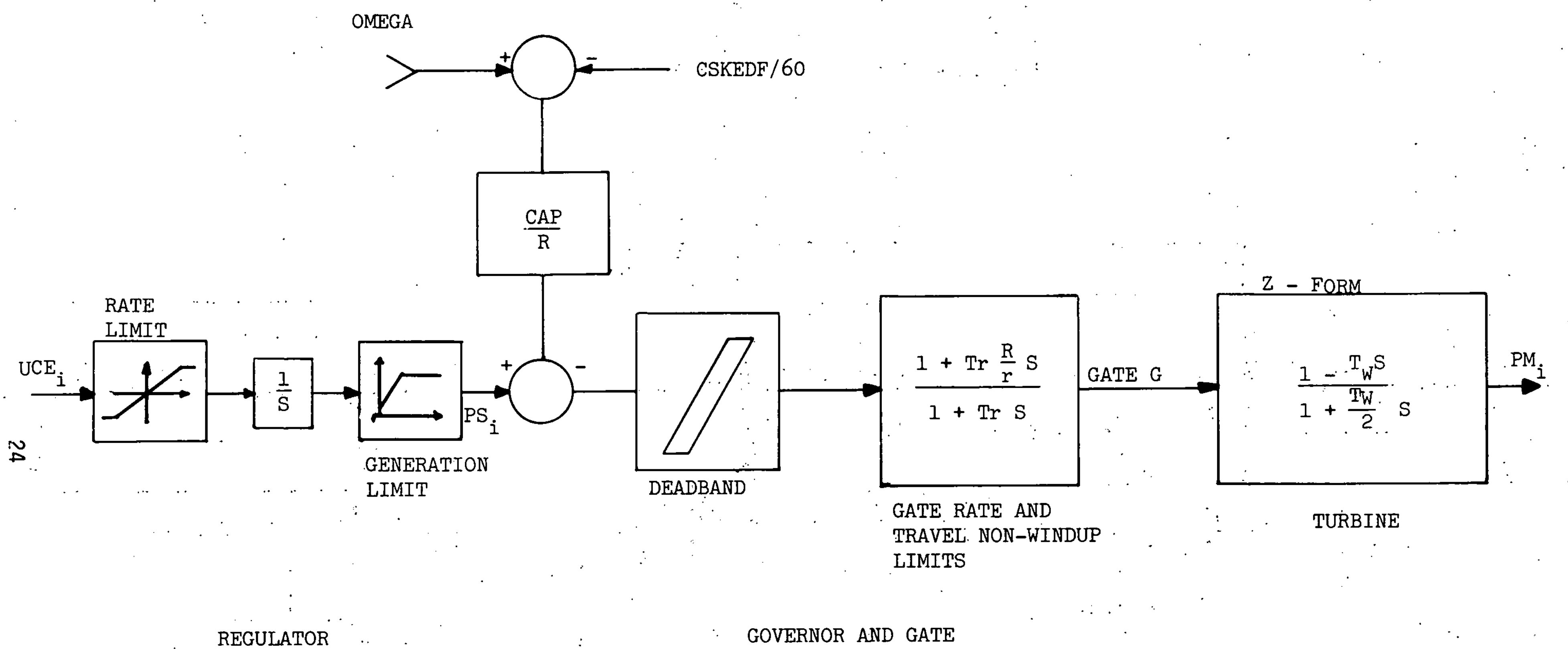


Fig. 4 MODEL OF HYDRO UNIT

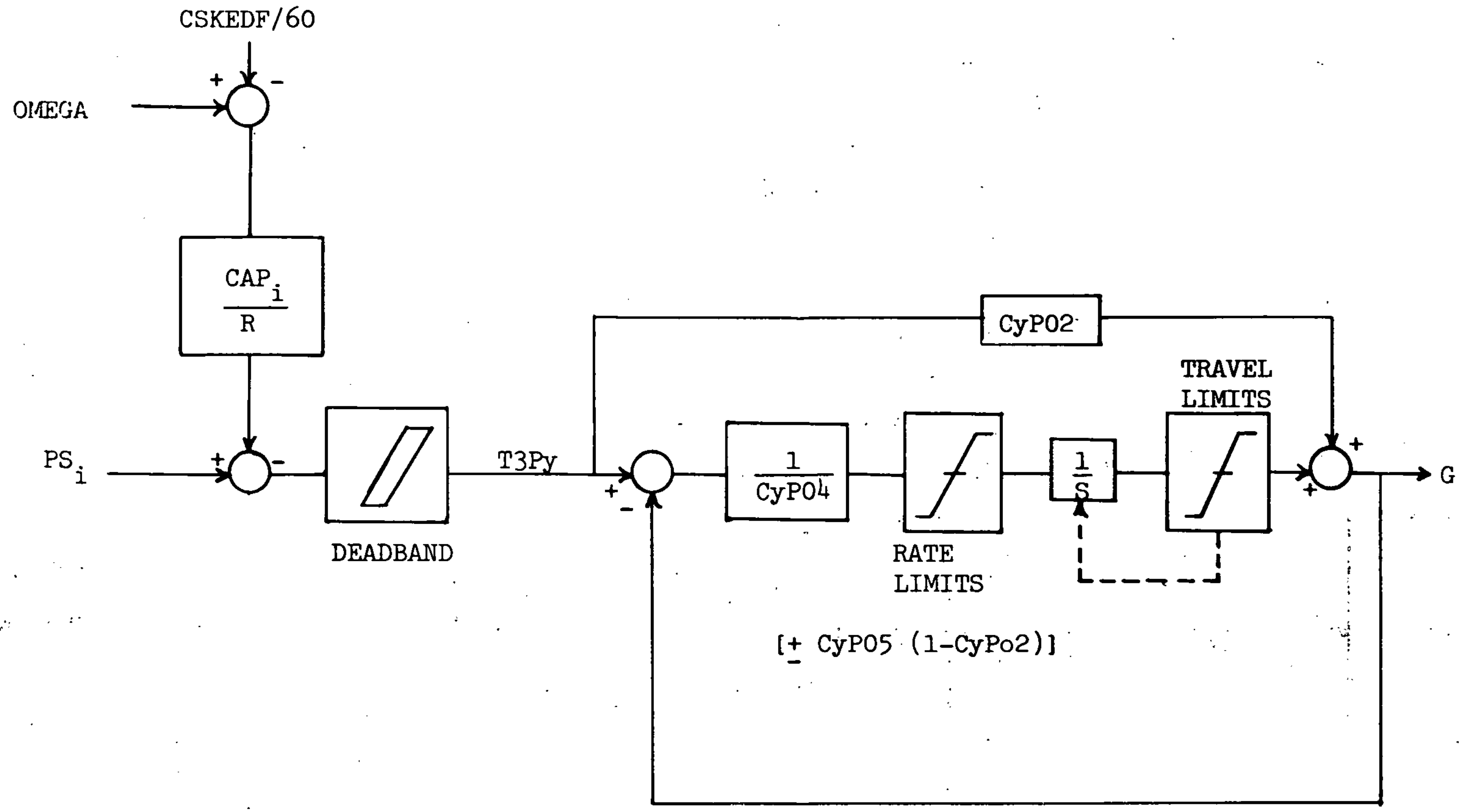
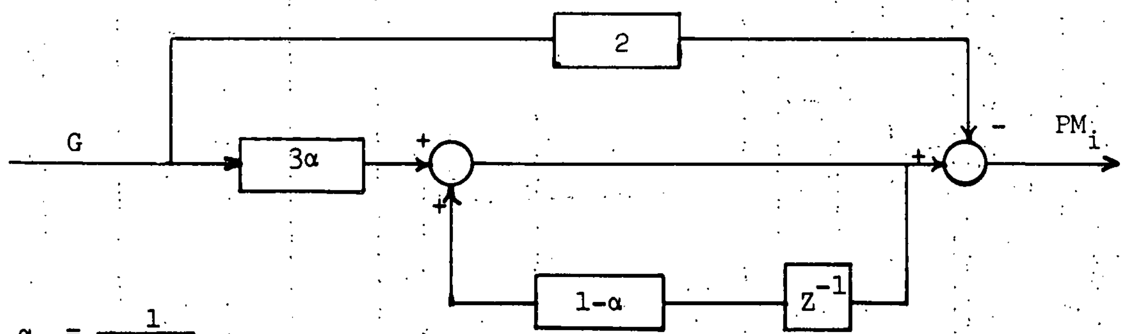


Fig. 5 DETAILED MODEL OF GOVERNOR AND GATE DYNAMICS FOR HYDRO UNIT



$$\alpha = \frac{1}{1 + \frac{T_W}{2\Delta}}$$

Δ = integration step size (1 sec)

Fig. 6 DETAILED MODEL OF TURBINE DYNAMICS (Z-FORM) FOR HYDRO UNIT the following table was obtained for that unit.

TABLE 2

K	Regulator Gain	1
R	Speed Regulation	.05
R/r	r is the transient regulation (CYPO2)	.125
CYPO3	Deadband	1.MW
T_r	Transient Droop Time Constant (CYPO4)	8 sec.
CYPO5	Rate of Gate Limit (MW rating/gate full travel time, sec.)	43.33 MW/sec
CYPO6	Gate Upper Limit	MW rating
CYPO7	Gate Lower Limit, MW corresponding to no load	0.MW
T_w	Water Starting Time	2. sec.

2.4 Boiling Water Reactor Model

This Boiling Water Reactor model represents General Electric reactors. It includes both the turbine generator and plant controls. The unit will respond to changes in automatic generation control (response to area control error) and system frequency. Those dynamics which should appear in a one-second integration step simulation have been included. These consist of changes in the recirculation flow and transient offset of the throttle pressure set point. Nuclear units of this type are base loaded on this system and do not respond to changes in area control error. A block diagram is given in Figure 7.

In Table 3 is a list of the variables and the values used in these simulations. This list also includes controller settings.

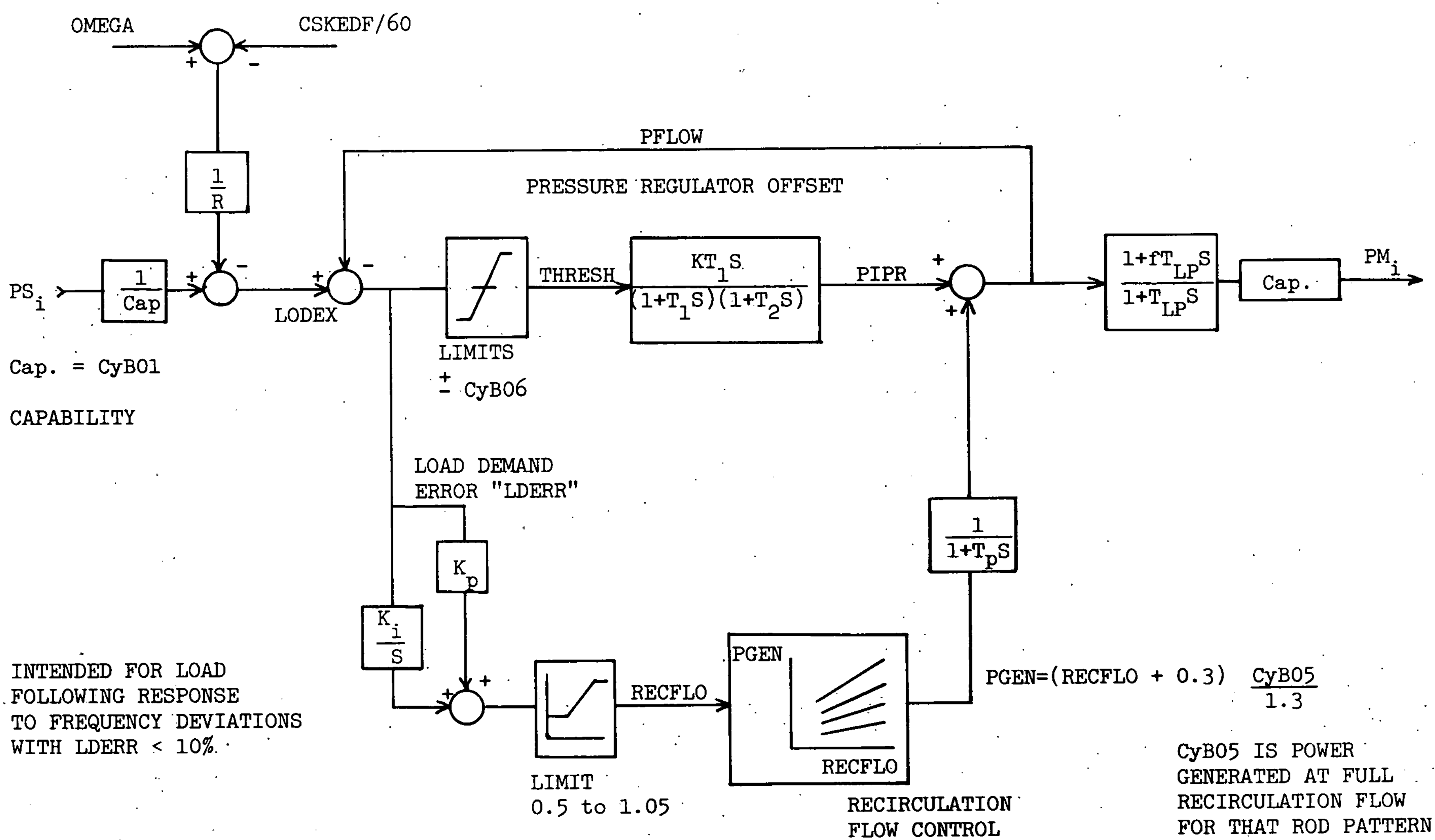


Fig. 7 MODEL OF BWR, TURBINE AND CONTROLS

TABLE 3

CAP	Capability,MW,per unit base for power	
K_P	Proportional part of recirculation control	0
T_P	In-core thermal time constant	7 sec.
K_I	Integral part of recirculation control	.15
CYBO6	Limit on signal to pressure regulator offset	$\pm .1$
K	Gain of pressure regulator offset	.6
T_1	Time constant of pressure regulator offset	25 sec.
T_2	Time constant of pressure regulator offset	5 sec.
f	Portion of power developed before the cross-over moisture separator	.3
T_{LP}	Time constant of steam flow in moisture separator and cross-over	4.5 sec.
R	Speed regulation	.05

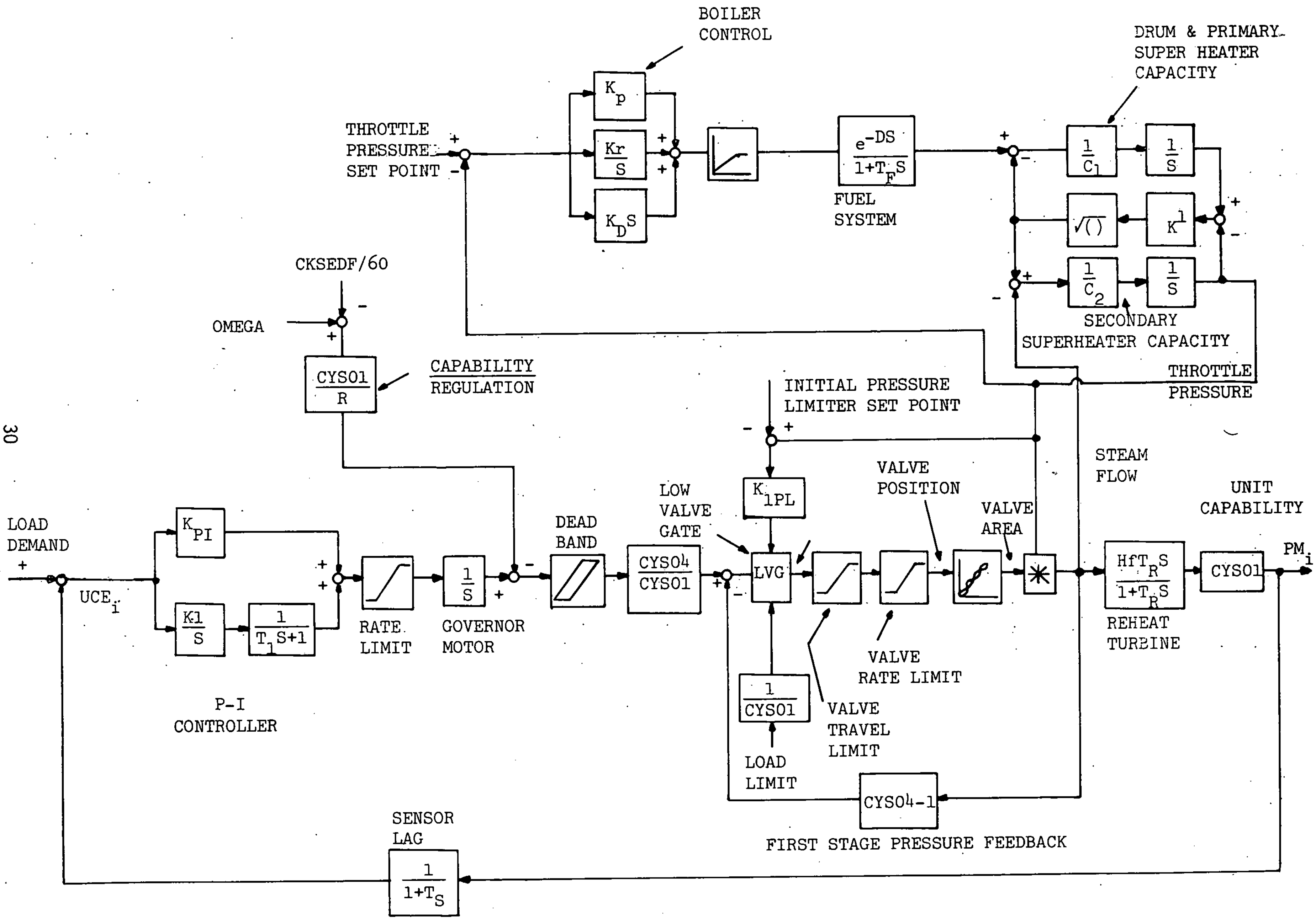
The power corresponding to full recirculation flow is PGEN, where PGEN = (RECFLO+.3)/1.3. Finally, it is apparent that the nuclear model is a per unit model and the governor set point input is expressed in per unit and the mechanical power output is converted back to magawatts. This model can be used for any size unit on the system as long as the appropriate initial conditions are supplied.

2.5 Fossil Fueled Drum Steam Turbine Model

The drum steam turbine generator model is shown in Figure 8. The fuel system dynamics affect the throttle pressure more than feedwater dynamics for a drum unit and thus feedwater dynamics are neglected. The fuel system dynamics will be very dependent on the use of coal or oil as a fuel and thus the fuel used will affect the transport delay and fuel system time constant.

The P-I controller, rate limiter, and integrator in the governor are included in the local dispatch office model but

Fig. 8 DRUM STEAM TURBINE GENERATOR MODEL



are shown here for completeness. This governor regulator is not shown in the gas turbine or boiling water reactor models because these units are base loaded and there is no need to represent the governor regulators.

Oil and coal fired drum units have been tested in the field, and the parameters of the governor valve characteristics, fuel system, and steam capacity have been based on these tests. The calculation of the steam capacity C_1 and C_2 and constant K^1 can be calculated for each case having a knowledge of the pressure and temperature profiles of the boiler and the volumes of the waterwall and superheater tubing. The following is data for an oil-fired drum type unit, Philadelphia Electric Company's Cromby No. 2 Unit. This model serves as the basic oil-fired drum-type unit for this system model.

TABLE 4

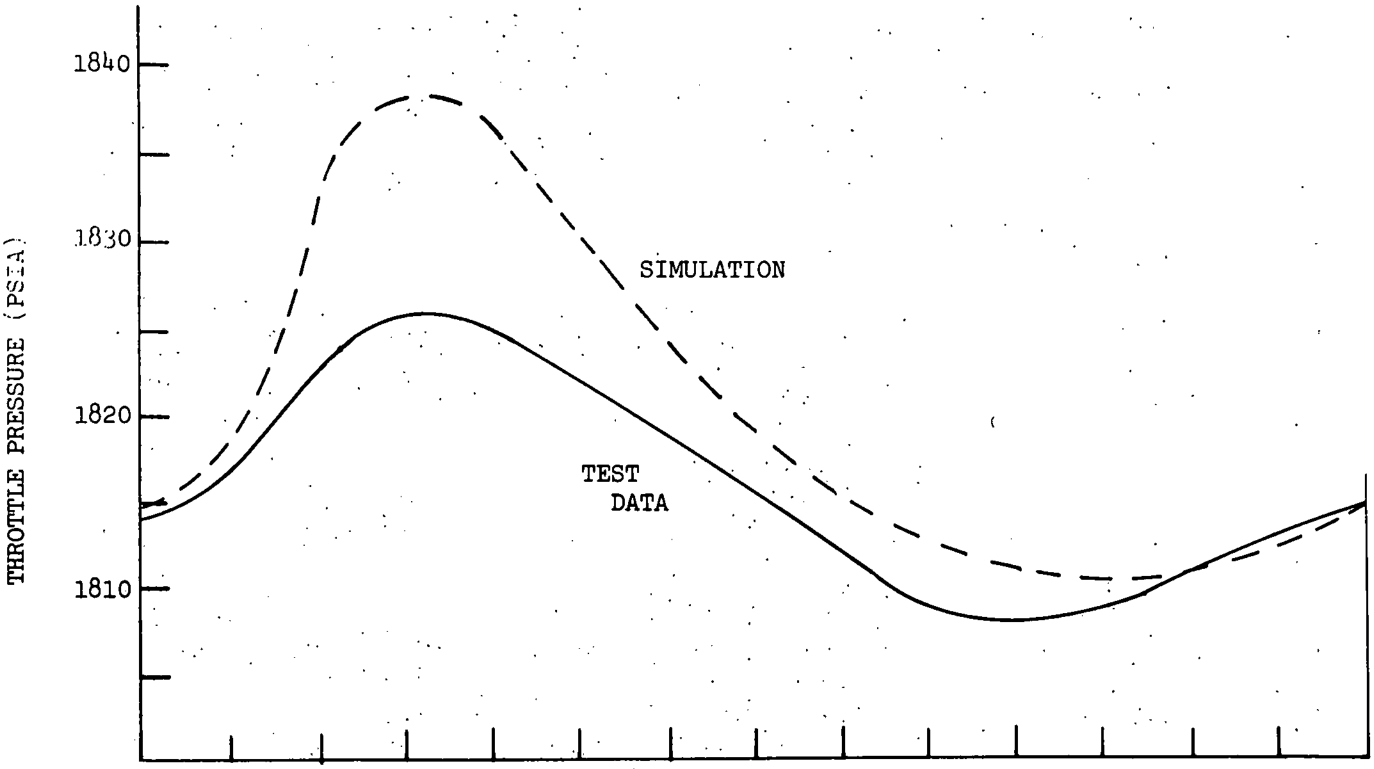
K_{P_1}	Gov. Control Proportional Gain	1.
K_{I_1}	Gov. Control Integral Gain	0.
T_1	Gov. Control Time Constant	100. sec.
CYSO1	Base Value of Unit Simulated	225. MW
R	Speed Regulation	.05
CYSO4	First Stage Pressure Feedback Indicator	1.
K_{1PL}	Initial Pressure Limiter Gain	10.
	Valve Rate Limit Opening	.025 $sec.^{-1}$
	Valve Rate Limit Closing	.100 $sec.^{-1}$
	Valve Travel Limit	0 to 1.0
	Initial Pressure Limiter Set Point	.85
	Speed Set Point (CSKEDF/60)	1.
	Load Limit	225 MW

TABLE 4 (Cont.)

f	Portion of Power Developed Before Reheater	.28
T_r	Reheat Turbine Time Constant	8 sec.
T_s	Sensor Lag Time Constant	1 sec.
IN	Per Unit Power (PM_i/CAP_i)	
K^1	Boiler Constant for Steam Flow	$\frac{1}{0.0606}(IN)^2$
C_1	Drum plus Primary Superheater Steam Capacity Representation	17.430 $sec.^{-1}$
C_2	Secondary Superheater Steam Capacity Representation	11.668 $sec.^{-1}$
D	Fuel Firing System Delay Time	6 sec.
T_F	Fuel System Time Constant	9 sec.
K_P	Boiler Control Proportional Gain	.8
K_I	Boiler Control Integral Gain	.015
K_D	Throttle Pressure Set Point, per unit	1.

Figure 9 shows a comparison between test data and the simulated model for both throttle and generation level change to an instantaneous change in setpoint PS_i. The model is a good approximation and indicates a relatively slow response. The simulation and test results are for a different rating than given in Table 4.

Data for a coal fired drum unit, Pennsylvania Power and Light Company's Brunner Island No. 2 unit, is given in Table 5 and is used as the basic coal fired drum unit in this system model.



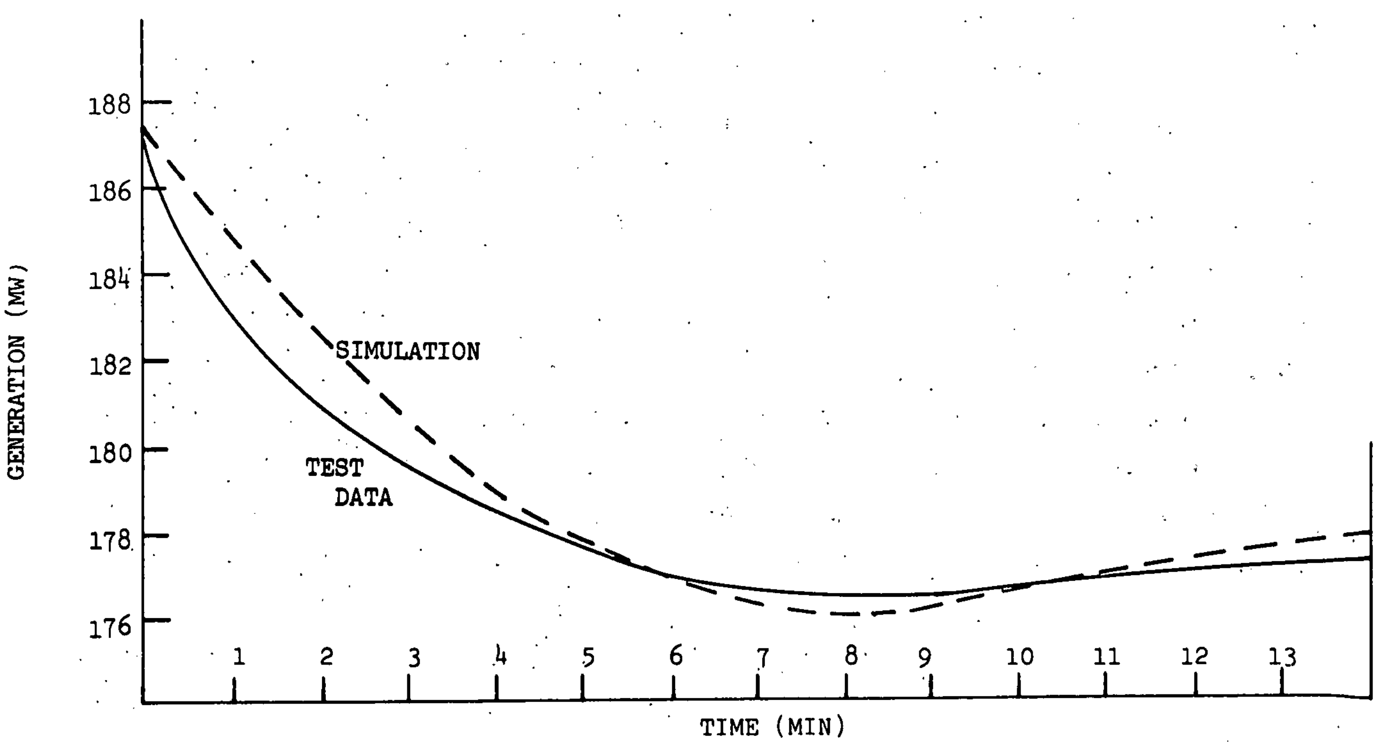


Fig. 9 RESPONSE OF OIL-FIRED DRUM UNIT (PJM)

TABLE 5

K_{P_1}	Gov. Control Proportional Gain	1.
K_{I_1}	Gov. Control Integral Gain	0.
T_1	Gov. Control Time Constant	100. sec.
CYS01	Base Value of Unit Simulated	225. MW
R	Speed Regulation	05.
CYS04	First Stage Pressure Feedback Indicator	1.
K_{1PL}	Initial Pressure Limiter Gain	10.
	Valve Rate Limit Opening	.025 $sec.^{-1}$
	Valve Rate Limit Closing	.100 sec^{-1}
	Valve Travel Limit	0 to 1.0
	Initial Pressure Limiter Set Point	.85
	Speed Set Point (CSKEDF/60)	1.
	Load Limit	225 MW
f	Portion of Power Developed Before Reheater	.28
T_R	Reheat Turbine Time Constant	8 sec.
T_S	Sensor Lag Time Constant	1 sec.
IN	Per Unit Power (PM_i/CAP)	
K^1	Boiler Constant for Steam Flow	$\frac{1}{0.0686}(IN)^2$
C_1	Drum plus Primary Superheater Steam Capacity Representation	11.430 $sec.^{-1}$
C_2	Secondary Superheater Steam Capacity Representation	11.668 $sec.^{-1}$
D	Fuel Firing System Delay Time	25.0 sec.

TABLE 5 (Cont.)

T_F	Fuel System Time Constant	30.0 sec.
K_P	Boiler Control Proportional Gain	.8
K_I	Boiler Control Integral Gain	.015
K_D	Boiler Control Derivative Gain	30.
	Throttle Pressure Set Point, per unit	1.

2.6 Fossil Fueled Once Through Turbine Model

The once-through units use a coordinated or integrated control system and feedwater dynamics instead of the fuel system dynamics. In this type of unit with an integrated control system, the governor controls act upon the megawatt loop, the boiler controls act upon the throttle pressure loop, and a cross-coupling exists between the two control loops. Pressure error is proportioned and entered into the governor control loop in addition to the load demand or megawatt error and the megawatt error is proportioned and added to the throttle pressure control loop along with the throttle pressure error. The feedwater dynamics are used in place of the fuel system dynamics because they are dominant in a once-through unit where there is no drum for separation of water and steam. The once-through unit has a continuous flow, dependent on the feedwater system and affecting the power output of the unit. These units are generally the most modern fossil fueled units on the system and have a faster long term response than a drum unit. Power is raised by increasing the feedwater flow in the boiler. However, without a drum which acts as a steam reservoir to take care of certain transients, tighter controls are needed on a once-through unit for stability and thus the integrated control scheme is used.

Once-through units are divided into subcritical and supercritical types. Both types can be modeled as shown in Figure 10.

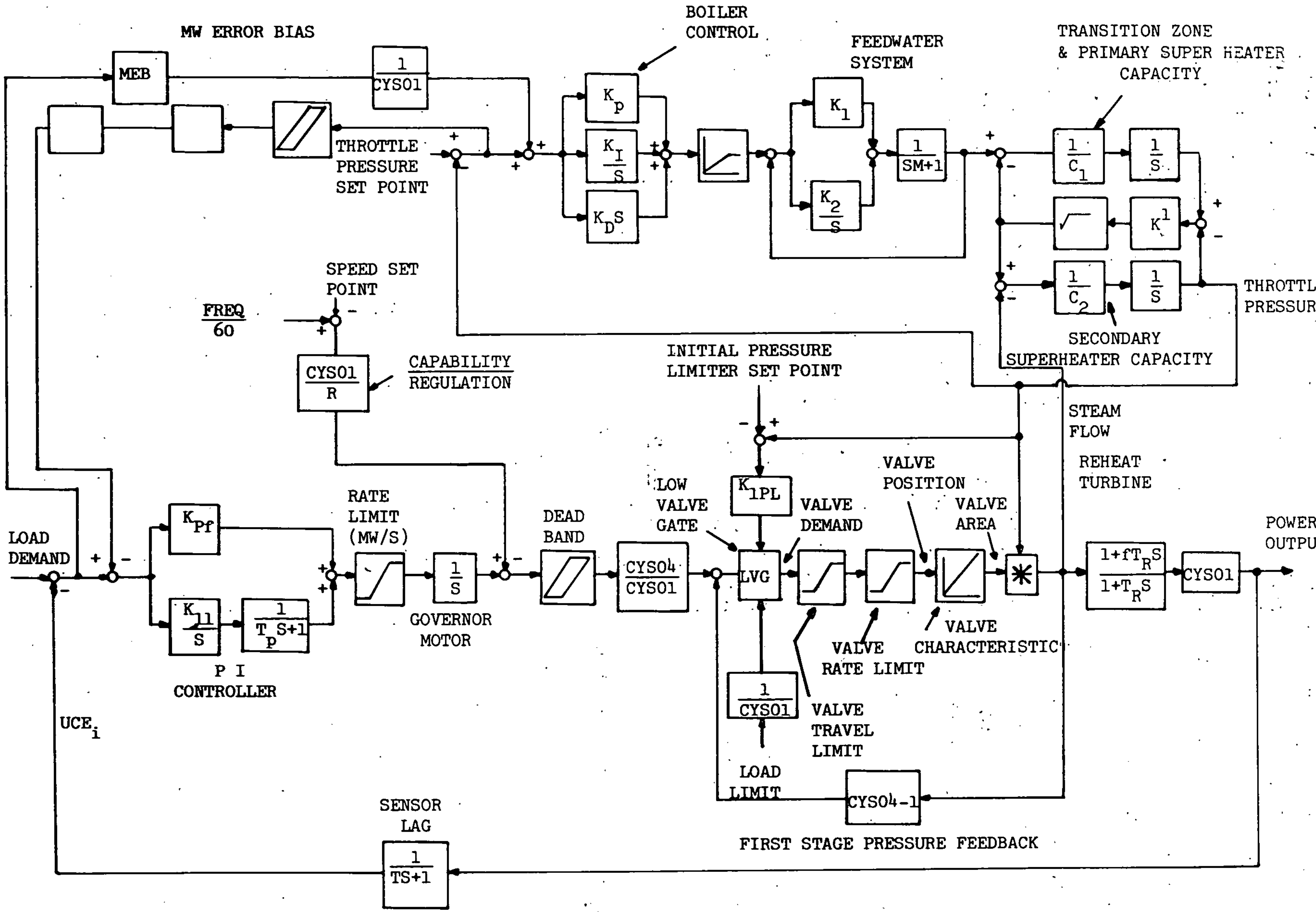


Fig. 10   FOSSIL FUELED ONCE-THROUGH UNIT MODEL

The governor model is shown in this figure for completeness even though it is actually modeled in the local dispatch office model. It should be noted that the governor is not shown in the block diagram of the turbine or boiling water reactor because they are base loaded in the PJM system and thus regulators would not be needed.

The parameter of these once-through units are also obtained from field test data. The parameters of the governor feedwater, and steam capacity models are based on these tests. The steam capacity C_1 and C_2 and boiler constant K^1 can be calculated as shown in [2] from knowledge of the pressure and temperature profiles of the boiler and the volumes of the waterwall and superheater tubing.

The values determined for the Baltimore Gas and Electric Company's Crane No. 1 sub-critical once-through unit are given in Table 6 and serve as the basic model for sub-critical once-through units in this system model.

TABLE 6

K_{P1}	Gov. Control Proportional Gain	.01
K_{I1}	Gov. Control Integral Gain	.1
T_1	Gov. Control Time Constant	100 sec.
CYSO1	Base Value of Unit Simulated	191 MW
R	Speed Regulation	.05
CYSO3	Deadband	.06 MW
CYSO4	First Stage Pressure Feedback Indicator	1.
K_{IPL}	Initial Pressure Limiter Gain	10
	Valve Rate Limit Opening	.025 $sec.^{-1}$
	Valve Rate Limit Closing	.100 $sec.^{-1}$
	Valve Travel Limit	0 to 1.0
	Initial Pressure Limiter Set Point	.85

TABLE 6 (Cont.)

	Speed Set Point (SKEDF/60)	1.
	Load Limit	191 MW
f	Portion of Power Developed Before Reheater	.28
T_R	Reheat Turbine Time Constant	8 sec.
T_S	Sensor Lag Time Constant	1 sec.
C_1	Transition Zone Plus Primary Superheater Steam Capacity Representation	27.042
IN	Per Unit Power (PM_i/CAP)	
K^1	Boiler Constant for Steam Flow	$(\frac{1}{0.0767})(IN)^2$
C_2	Secondary Superheater Steam Capacity Representation	6.0417
K_1	Feedwater System Proportional Gain	.9881
K_2	Feedwater System Integral Gain	.0214
M	Feedwater System Inertia Time Constant	20 sec.
K_P	Boiler Control Proportional Gain	4.5
K_I	Boiler Control Integral Gain	.03
K_D	Boiler Control Derivation Gain	44.
	Throttle Pressure Set Point, per unit	1.
MEB	Megawatt Error Bias	.0382
PEB	Pressure Error Bias	3.926
	Pressure Error Deadband	.004

Figure 11 shows the test data and simulated response data for throttle pressure and generation for this subcritical once through unit. The response is much more rapid than the drum unit.

The associated data for the Pennsylvania Power and Light Company's Brummer Island No. 3 supercritical once through unit is given in Table 7 and is the basic unit in this system model.

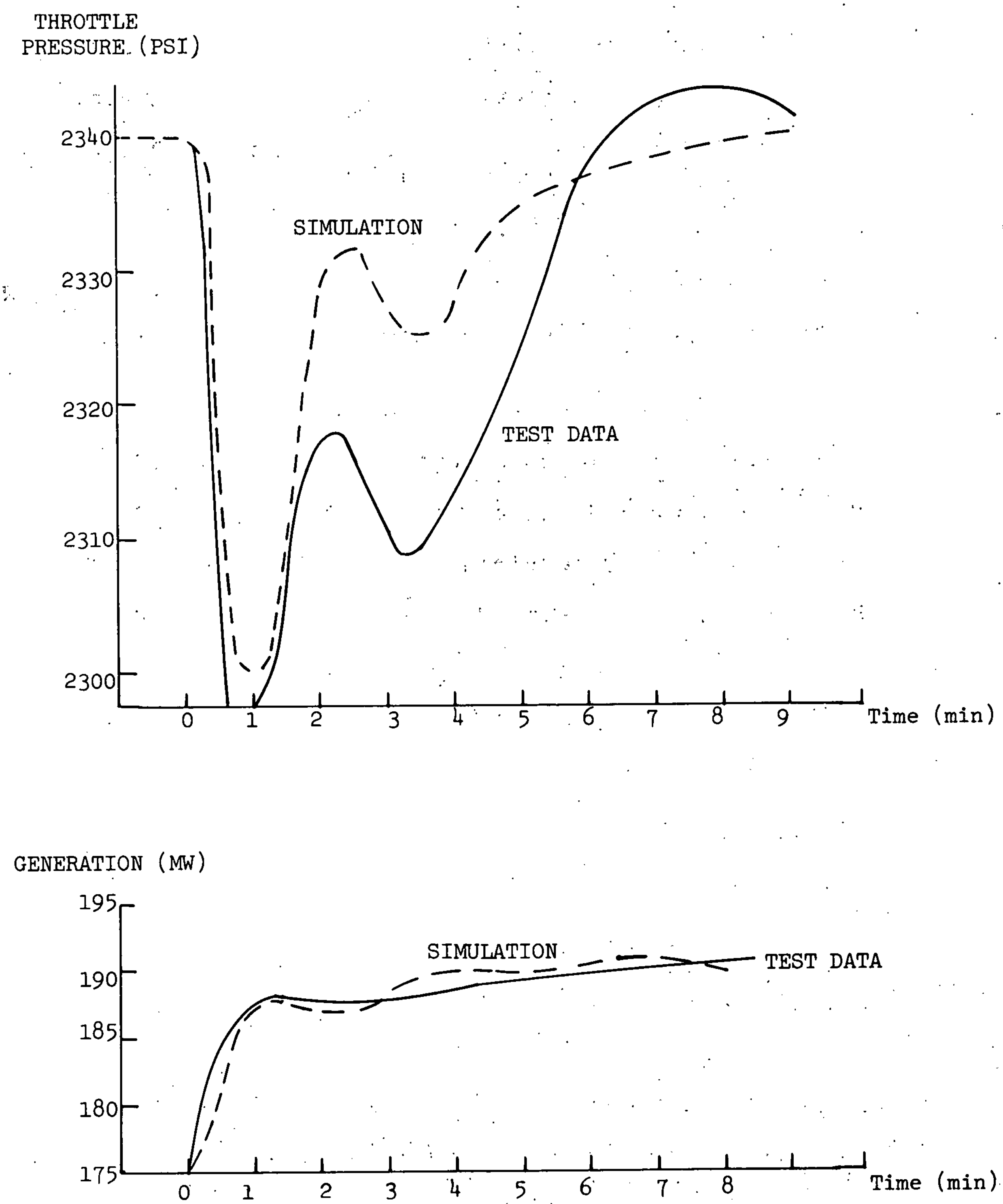


Fig. 11 RESPONSE OF SUBCRITICAL ONCE-THROUGH UNIT

TABLE 7

K_{P_1}	Gov. Control Proportional Gain	.095
K_{I_1}	Gov. Control Integral Gain	0.
T_1	Gov. Control Time Constant	175 sec.
CYSO1	Base Value of Unit Simulated	745 MW
R	Speed Regulation	.05
CYSO3	Deadband	.3 MW
CYSO4	First Stage Pressure Feedback Indicator	1.
K_{1PL}	Initial Pressure Limit Opening	.025 $sec.^{-1}$
	Valve Rate Limit Opening	.100 $sec.^{-1}$
	Valve Travel Limit	0.
	Initial Pressure Limiter Set Point	.85
	Speed Set Point	1.
	Load Limit	745. MW
	Portion of Power Developed Before Reheater	.28
T_R	Reheat Turbine Time Constant	8. sec.
T_S	Sensor Lag Time Constant	1. sec.
C_1	Transition Zone Plus Primary Superheater Steam Capacity Representation	6.5938
IN	Per Unit Power (PM_i/CAP)	
K^1	Boiler Constant for Steam Flow	$\frac{1}{.0628}(IN)^2$
C_2	Secondary Superheater Steam Capacity Representation	3.8771
K_1	Feedwater System Proportional Gain	.9881
K_2	Feedwater System Integral Gain	.0214
M	Feedwater System Inertia Time Constant	20 sec.
K_P	Boiler Control Proportional Gain	1.76
K_I	Boiler Control Integral Gain	.112

TABLE 7 (Cont.)

K_D	Boiler Control Derivative Gain	88.
	Throttle Pressure Set Point, per unit	1.
MEB	Megawatt Error Bias	.00069
PEB	Pressure Error Bias	750.
	Pressure Error Deadband	.006 MW

Figure 12 shows the test and simulated response of this supercritical once through unit and again this response rate is much higher than for drum unit. Note that this supercritical unit is much larger than the sub-critical unit.

2.7 External Area Model

The external area model is divided into three sections; a load-frequency control mode, a prime mover model representing a slow fossil fueled boiler turbine set, and an external area load model. The first two sections are shown in Figure 13. The external area control error, ACEEXT, is developed from the tie flow deviation from schedule and the frequency error. This signal passes through a telemetry delay of three seconds to the governor motor to form the governor motor set point. The set point and speed droop are added to form the input to the prime mover section, whose output is fed into the reheat steam turbine dynamics. The mechanical power of the external area, PMEXT, is the output. A list of definitions of the various parameters is given below:

TABLE 8

CEXT01	Frequency Bias	.09 Capability
CEXT02	ACE Gain	.05
CEXT03	DEADBAND	108. MW
CEXT04	Pressure Drop Factor(C)	.16
CEXT05	Boiler Lag(T_B)	360. sec.

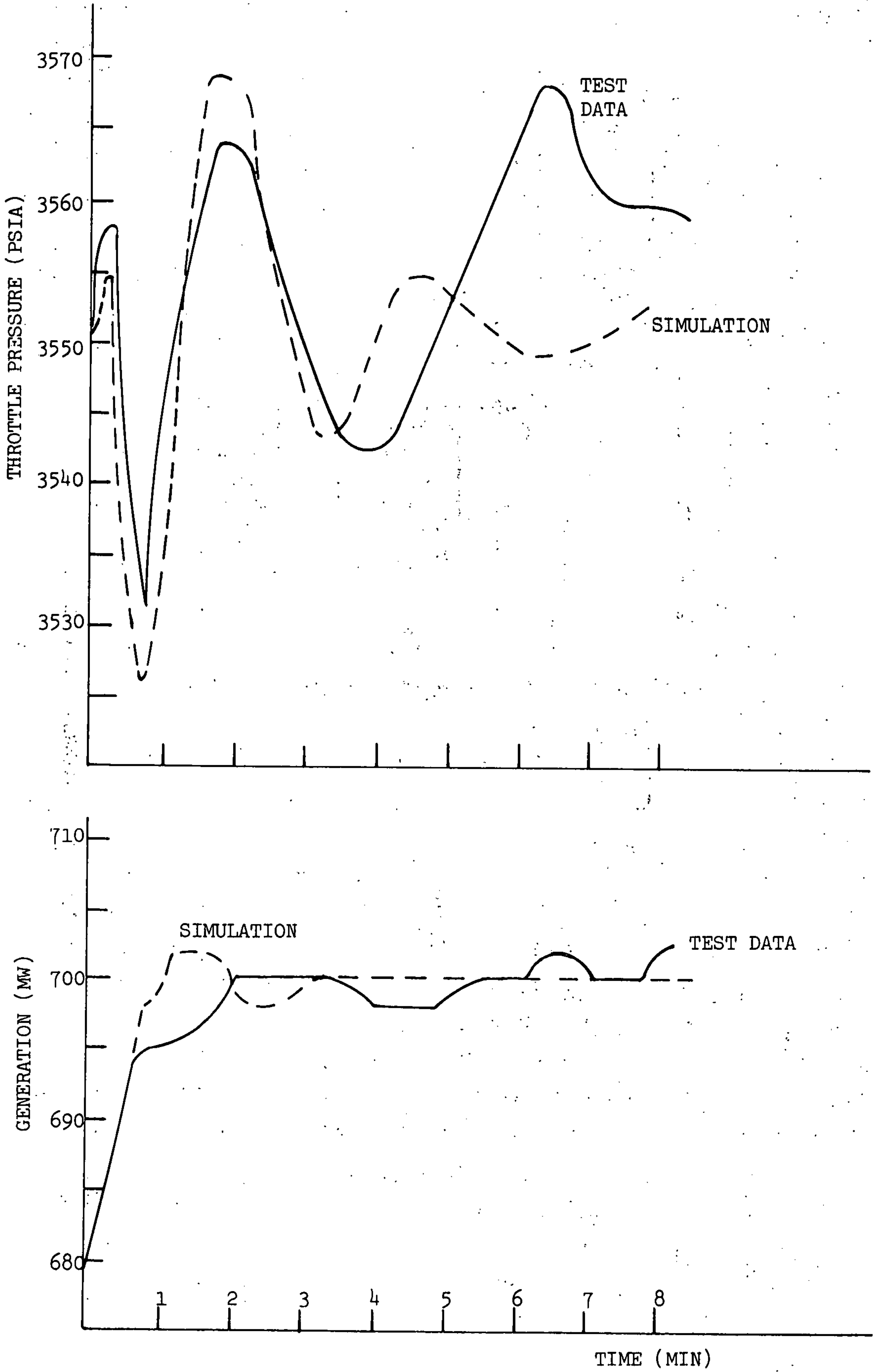


Fig. 12 RESPONSE OF THE SUPERCRITICAL ONCE-THROUGH UNIT (PJM)

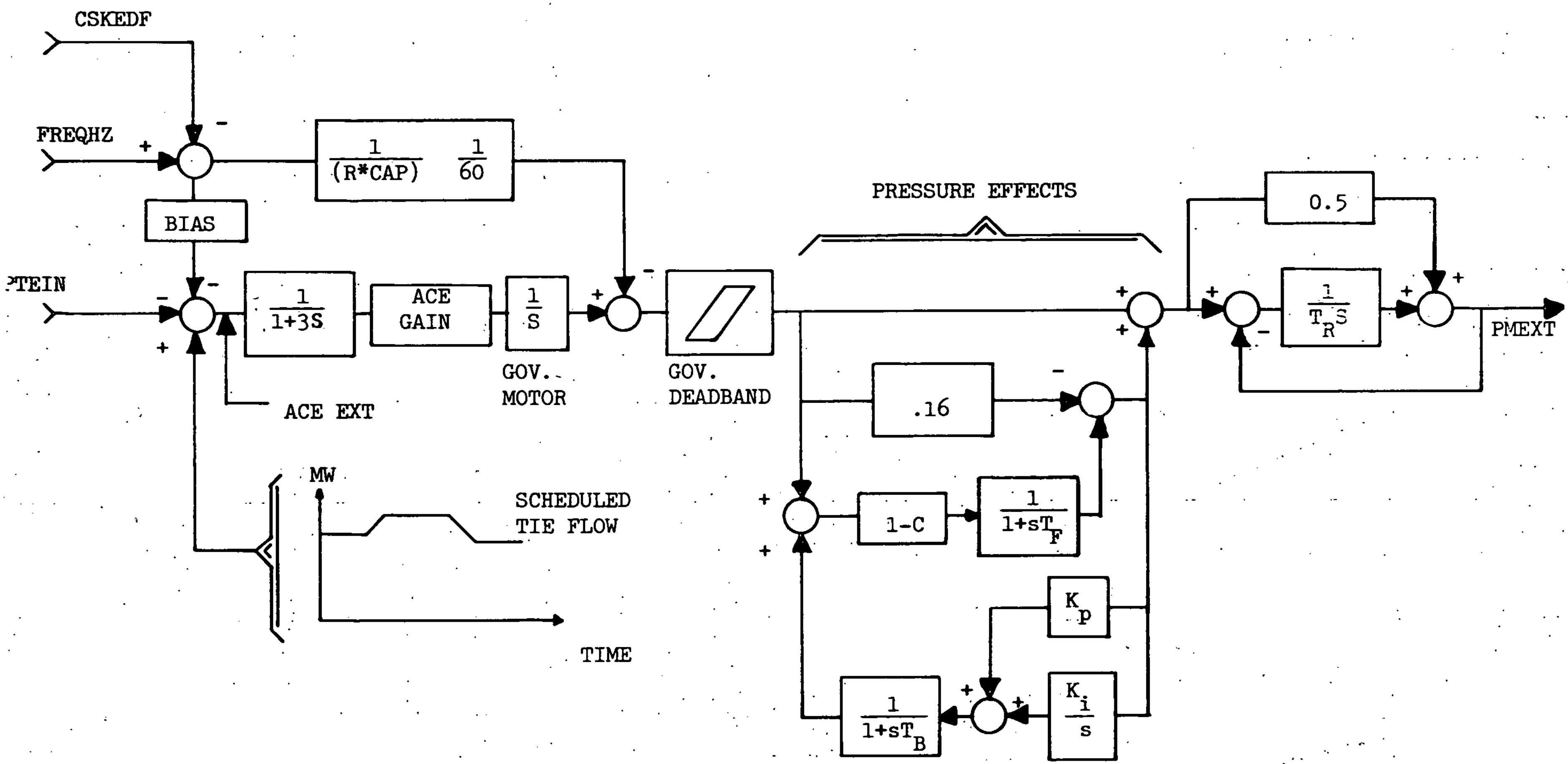


Fig. 13 EXTERNAL AREA MODEL

TABLE 8 (Cont.)

CEXT06	Firing Lag (T_F)	60. sec.
CEXT07	Proportional Control	.75
CEXT08	Integral Control	.005
CEXT09	Non Reheat Portion	.5
CEXT10	Reheat Lag (T_R)	8. sec.
CEXT11	Speed Droop $\left(\frac{\text{CAPABILITY}}{R}\right)$	2,205,000.

The parameters of this model are chosen specifically for the PJM system and were tuned to give proper response characteristics of the external system.

2.8 Load Model

The load model section of the external area as well as the PJM load model is not completed. Due to a lack of statistical data for the system, a statistical load model has not been developed. Instead, actual system test data are fed into the model. Since these data include many types of operating conditions they are considered to be very representative. Using these data, the model was validated for four separate conditions.

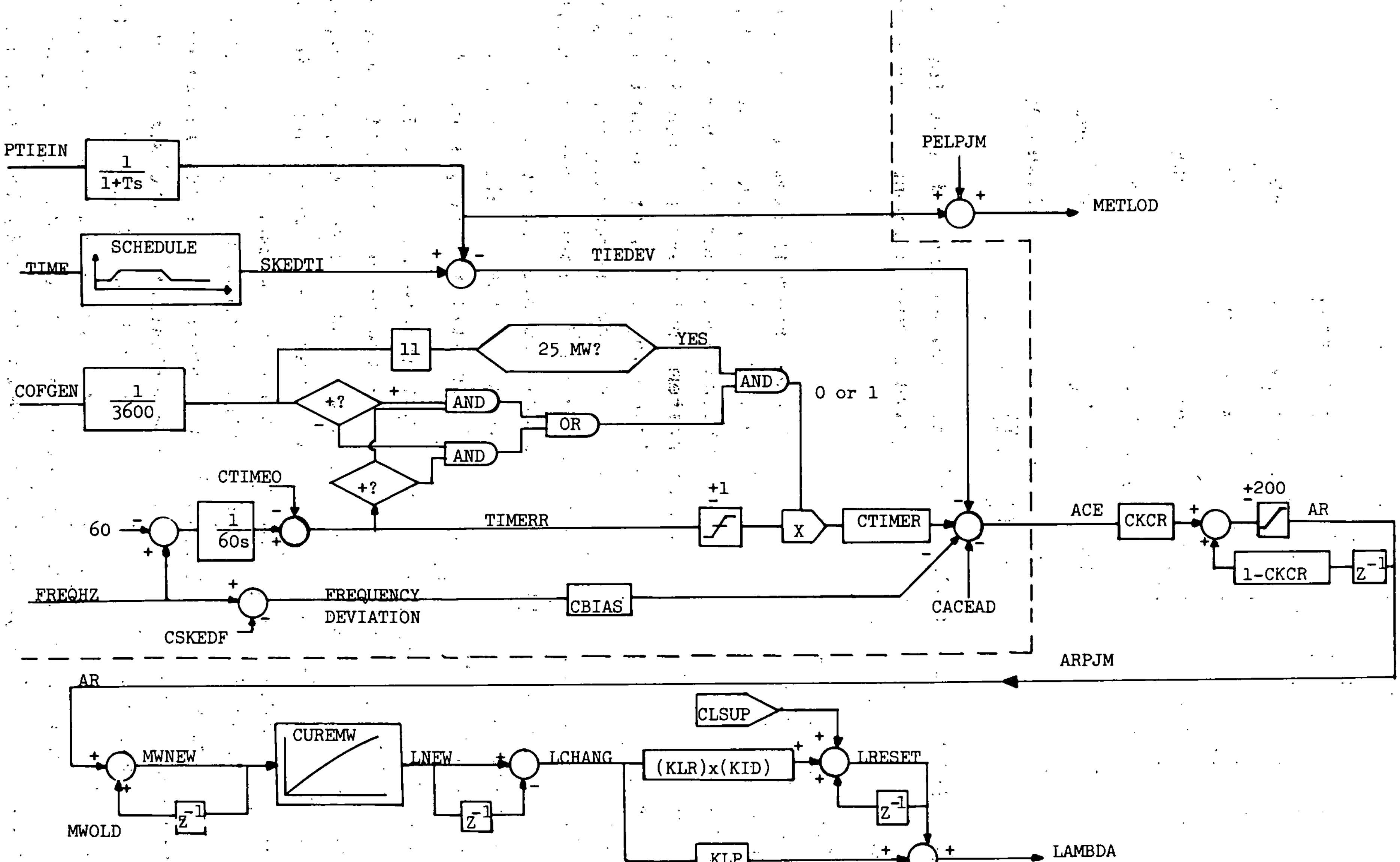
This completes the model used to produce prime mover mechanical powers into the lumped inertia model. Models of the local and central dispatch offices will now be presented.

2.9 Central Load Dispatch Office (Subroutine UPDATE)

The model shown in Figure 14 represents the LDO located in Valley Forge, PA. It simulates the control computer dynamics of the ACE-AR-Lambda algorithm. The basic inputs are tie flow and frequency. The outputs are AR and Lambda.

The Area Control Error (ACE) is formed as the sum of tie flow deviation, frequency bias, accumulated interchange error, and manual input. The tie flow deviation is the sum of the telemetered tie flow (PTIETM), and scheduled tie flow (SKEDTI). PTIETM is the actual tie flow after it has been delayed by a time constant CTTEIM. Scheduled tie flow, SKEDTI, is formed from a function generator, dependent on TIME, by linear interpolation.

Fig. 14 CENTRAL DISPATCH OFFICE



Off generation, OFFGEN, is the accumulated value of interchange error, put in the initial conditions of a simulation as COFGEN. Time error, TIMERR, is the integral of frequency deviation plus an initial value of CTIMEO. If the off generation exceeds 25 MW and is in a direction not to act to increase time error, then the time error is weighted by CTIMER to offset ACE to reduce both TIMERR and OFFGEN. Frequency, FREQHZ, is compared to scheduled frequency, CSKEDF, and the difference biased by CBIAS to form the frequency bias.

A constant CACEAD is included to represent the dispatcher's manual additions to correct for known errors.

The manual time error and interchange error corrections are not included in the FORTRAN simulation because they were not essential for this study.

The Area Requirement, AR, if formed by a digital filter using CKCR as a delay variable. CKCR is related to the filter time constant by

Ln (1-CKCR)=-(Time Step)/TIME CONSTANT=-1/TIME CONTANT=0.16

time step=1 sec.

LAMBDA is formed from the area requirement by a proportional plus reset controller. MWNEW is an accumulated value of AR. It is used in the system cost function table to obtain LNEW. This table is presently a straight line. LCHANG is approximately the rate of change of LNEW. LCHANG is proportional to AR because of the linear cost function. LAMBDA is the sum or a proportional part of LCHANG with gain CKLP, a proportional part of the integral of LCHANG with gains KLR times KLD, and a proportional part of the integral of LSUP, the supplementary input from the dispatcher.

2.10 Local Load Dispatch Offices

The Load Dispatch Offices (LDO) represent the control centers on each member's system. They receive the economic cost signal, LAMBDA, and the area requirement, AR, from the Central Load Dispatch Office and the generation level PM_i from each of their units. Their output is the command signal, UCE_i, to each unit. This model is described in Figure 15. Each of the member company LDO's is similar. The economic cost signal

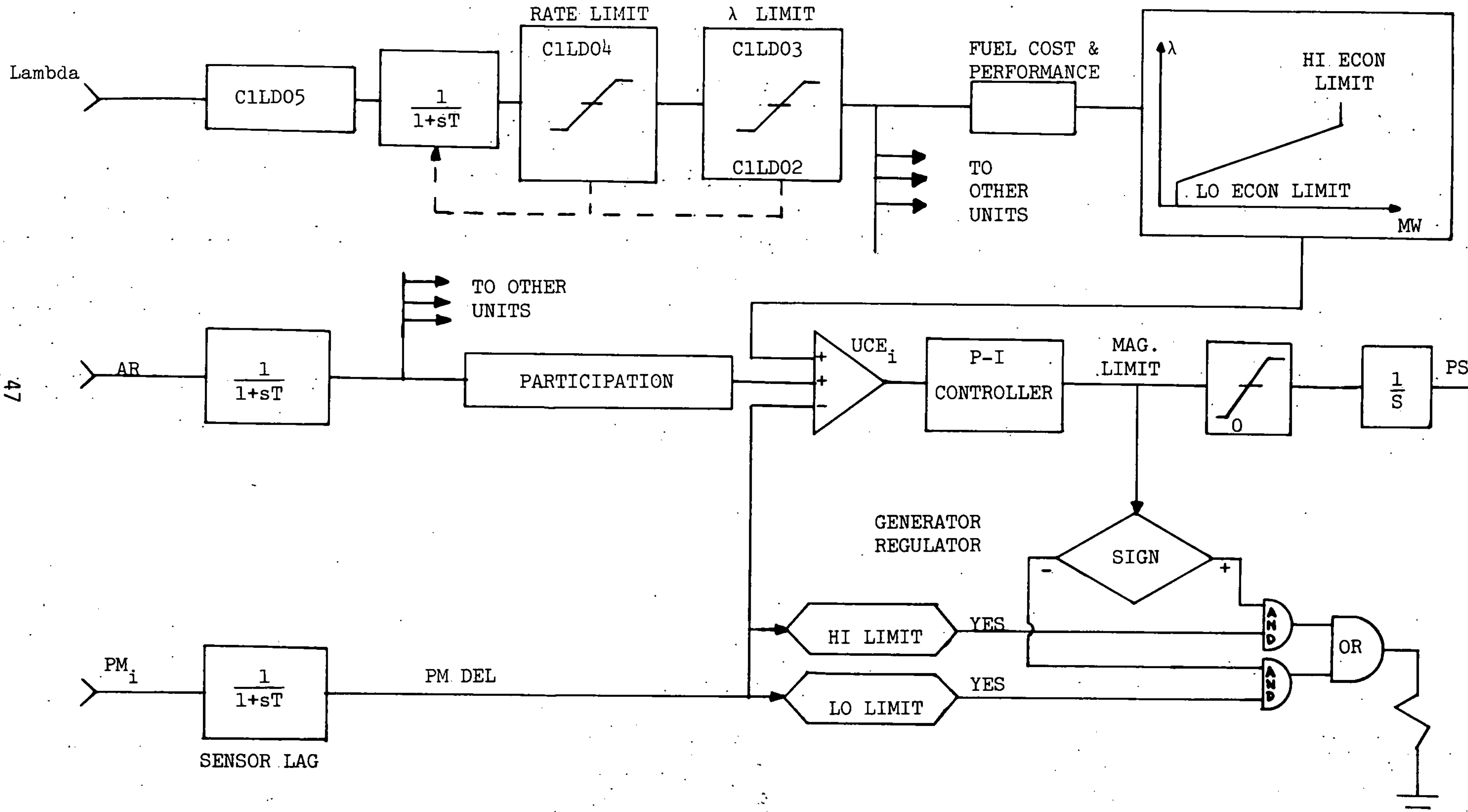


Fig. 15 LOCAL LOAD DISPATCH OFFICE

passes through a dispatch algorithm to produce a company cost and then through each unit's cost curve to develop the desired megawatt signal for each generator. The system area requirement signal passes through an Automatic Generation Control algorithm to produce that company's participation in the AR commitment. Finally, each unit's generation passes through the telemetry system dynamics and is subtracted from the sum of the desired economic generation for that unit and its AR participation. This megawatt error signal then passes through the governor regulator controls to the governor motor.

A further description of the central and local dispatch office is included in Section 5 when the dynamic response of the automatic generation control economic dispatch is analyzed.

3. WIND ARRAY MODEL

The wind array model is developed by first considering the model for a single wind turbine generator and then developing a model of the correlation between the wind at different generators in an array for a thunderstorm gust front.

The model of each WTG used in the wind array model assumes that the performance of the automatic generation control-economic dispatch and unit commitment strategies are too slow in response to generation or load changes to be affected by

(1) the dominant modes [7,8] of a single or multiple WTG configuration as seen from the EHV transmission network under normal operating conditions;

(2) "tower shadow" [9] or spurious internal disturbances and their interaction with turbine generator dynamics;

(3) the effects of wind gusts and their interaction with turbine generator dynamics

A static nonlinear model [for a Mod 1 WTG], that relates wind speed V_W and mechanical power to the generator shaft PMW(t) and shown in Figure 16, is thus assumed to be sufficient to model the changes in mechanical shaft power on a WTG due to wind speeds in a thunderstorm gust front. The resulting WTG model for normal operating conditions is shown in Figure 17

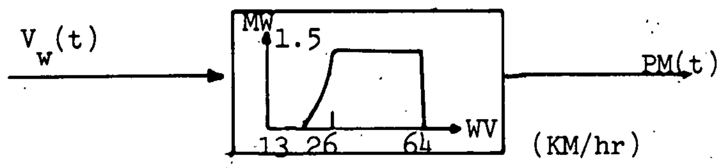


Fig. 16 STEADY-STATE RELATION BETWEEN WIND VELOCITY AND WTG MECHANICAL POWER

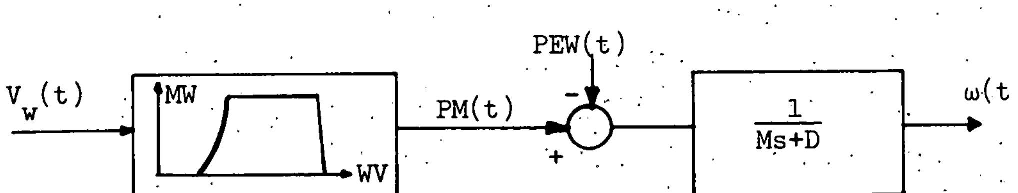


Fig. 17 DYNAMIC MODEL FOR WTG UNDER NORMAL OPERATING CONDITIONS

where PEW(t) is the electrical power produced by the WTG, $\omega(t)$ is the electrical frequency of the generator, and M and D are the inertia and damping factors for the WTG. This model is quite sufficient for wind fronts that do not have speeds in excess of 64 km/hr.

The WTG model, shown in Figure 16, must also include a model of the shutdown and startup sequences that occur when the average wind speed exceeds 64 km/hr and a shutdown of the generator is triggered. This shutdown-startup sequence, that avoids damage due to high winds, must be included in the WTG model because

(1) the changes in generation are large (1.5 MW/machine) and almost instantaneous for both shutdown and startup

(2) the times at which a shutdown or startup occurs at each generator in the array has a very important effect on the changes in power out of the wind array during a thunderstorm gust front with wind speed profiles as shown in Figure 18. The changes in power out of an array is particularly affected by this shutdown-startup sequence - if there are multiple echelons in the array and if thunderstorm fronts have wind speed peaks that can trigger such a shutdown

A shutdown of a generator will only occur when the average wind speed as observed from a one minute filter

$$\hat{V}(kT) + \frac{(1-\frac{120}{T})}{(1+\frac{120}{T})}\hat{V}(kT-T) = (\frac{1}{1+\frac{120}{T}})[V_W(kT) - V_W(kT-T)]$$

with sampling period T, exceeds 64 km/hr. If a shutdown is triggered, the rotor blade pitch angle is slewed at a -30°/min rate from the angle at maximum capacity at 64 km/hr(-18°) to feather (-90°). As this rotor blade pitch angle is slewed, power is very quickly lost ($\sim$4 second) because Figure 19 shows that only a 2° change is necessary for loss of power at 64 km/hr. The rotor angle continues to be slewed to feather even after loss of power, and takes approximately 144 seconds if the filtered wind speed remains above 53 km/hr for the entire 144 seconds.

If the filtered wind speed $\hat{V}(kT)$ drops below 53 km/hr, after the machine has feathered and the rotor has stopped spinning, a regular startup sequence is initiated in which

(1) the rotor blade pitch angle slews from -90° back toward zero degrees at a rate of 36°/min until the rotor attains a 5 rpm speed. Since the blade angle must reach -17.5°, from Figure 17, before any power is obtained at a 53 km/hr wind speed, it is assumed that the blade pitch angle must be greater than -17.5 for acceleration of the rotor shaft. This acceleration to 5 rpm is assumed to occur very rapidly after the rotor blade angle reaches -17.5°

(2) the rotor shaft is accelerated from 5 rpm to 40 rpm at a constant 15 rpm/min rate by adjusting accelerating torque through control of the rotor blade pitch angle

(3) synchronization of the machine into the grid occurs only a few seconds after the machine reaches synchronous speed. The phasing for synchronization is adjusted by perturbing blade pitch angle and thus torque.

If the filtered wind speed drops below 53 km/hr before the rotor blade has been fully feathered and before the rotor has stopped rotating, an early startup procedure is begun which

(1) slews the rotor blade pitch angle from the value it is when $\hat{V}(kT)$ first comes below 53 km/hr back toward zero degrees at a rate of 36°/min. A -17.5° blade pitch angle, at which the shaft is assumed to start accelerating, from Figure 19, is thus achieved in much less than the 120 seconds required when slewed from the feathered position.

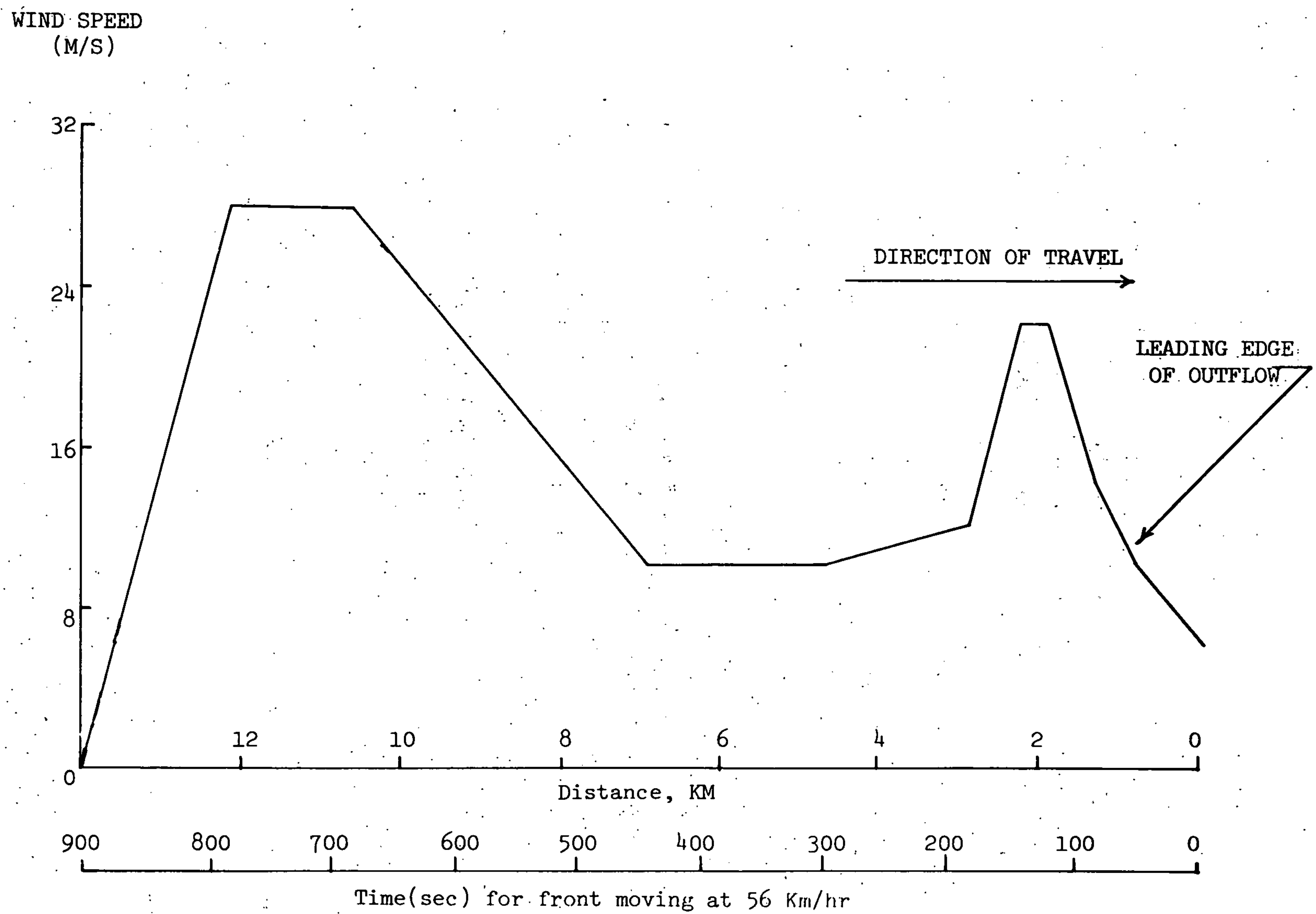


Fig. 18 WIND SPEED PROFILE OF A STORM FRONT (12)

The rotor speed will not drop below 5 rpm if the machine is restarted before it is feathered because Figure 20, [8], which shows the response of the speed control loop, for an overspeed condition, indicates the speed control system will cause a 2 rpm/sec decay rate on the high speed shaft if there is no accelerating power from the rotor. This 2 rpm/sec decay rate on the high speed shaft translates into a $\frac{2}{45}$ rpm/sec decay rate on the slow speed shaft. Thus, the speed on the low speed shaft will only decay 18 rpm in the 264 seconds needed to bring the rotor blade pitch to feather and back if a startup was triggered at the instant the blade just reached the feathered position.

(2) the rotor speed control accelerates the rotor speed from the value it has when the blade pitch angle returns to -17.5 and changes rotor speed at a 15 rpm/min rate unitl a 40 rpm speed is obtained

(3) synchronization with the grid is again obtained quickly by adjusting blade pitch angle and torque to obtain proper phasing

An analysis of the changes in rotor blade pitch angle and rotor speed during a shutdown-startup sequence during a thunderstorm gust front is included when the wind farm response to the thunderstorm front (Figure 18) is analyzed in Part II of this report.

A second shutdown-startup sequence is used when average wind speed drops below 13 km/hr. In this case no power is lost because the generator is not producing any net power into the grid when the sequence is initiated. The startup is not initiated unless average wind speed attains 21 km/hr. This shutdown-startup sequence is only important because it would indicate the times when a generator is triggered off-line and when it again can be resynchronized. This shutdown-startup sequence, which avoids drawing power from the network to main-

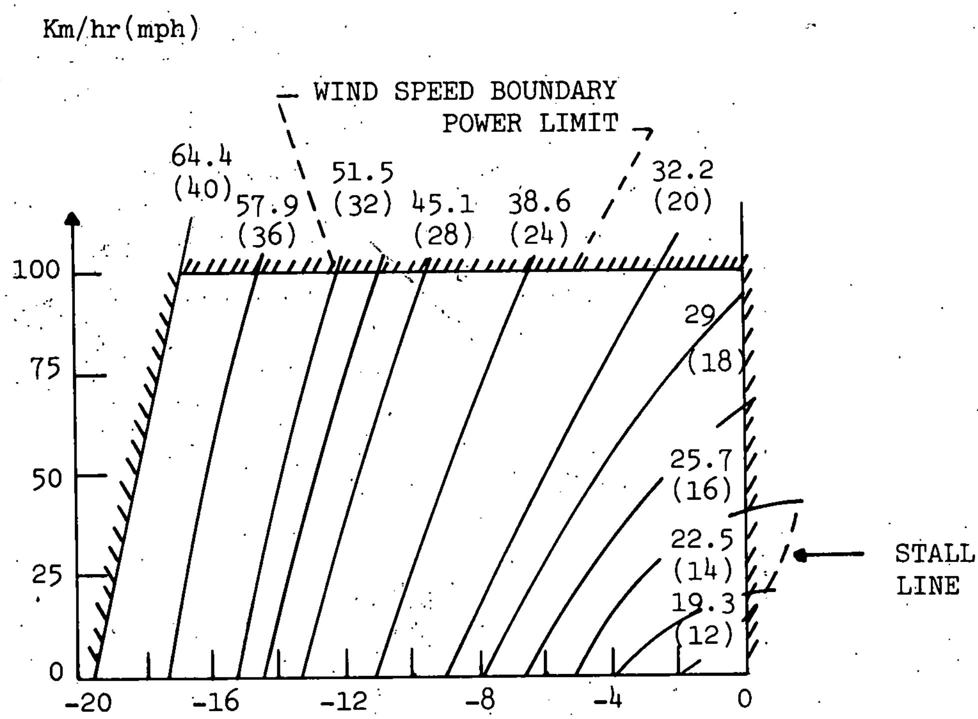


Fig. 19 ALTERNATOR POWER VS BLADE ANGLE FOR VARIOUS WIND SPEEDS (MOD 0)

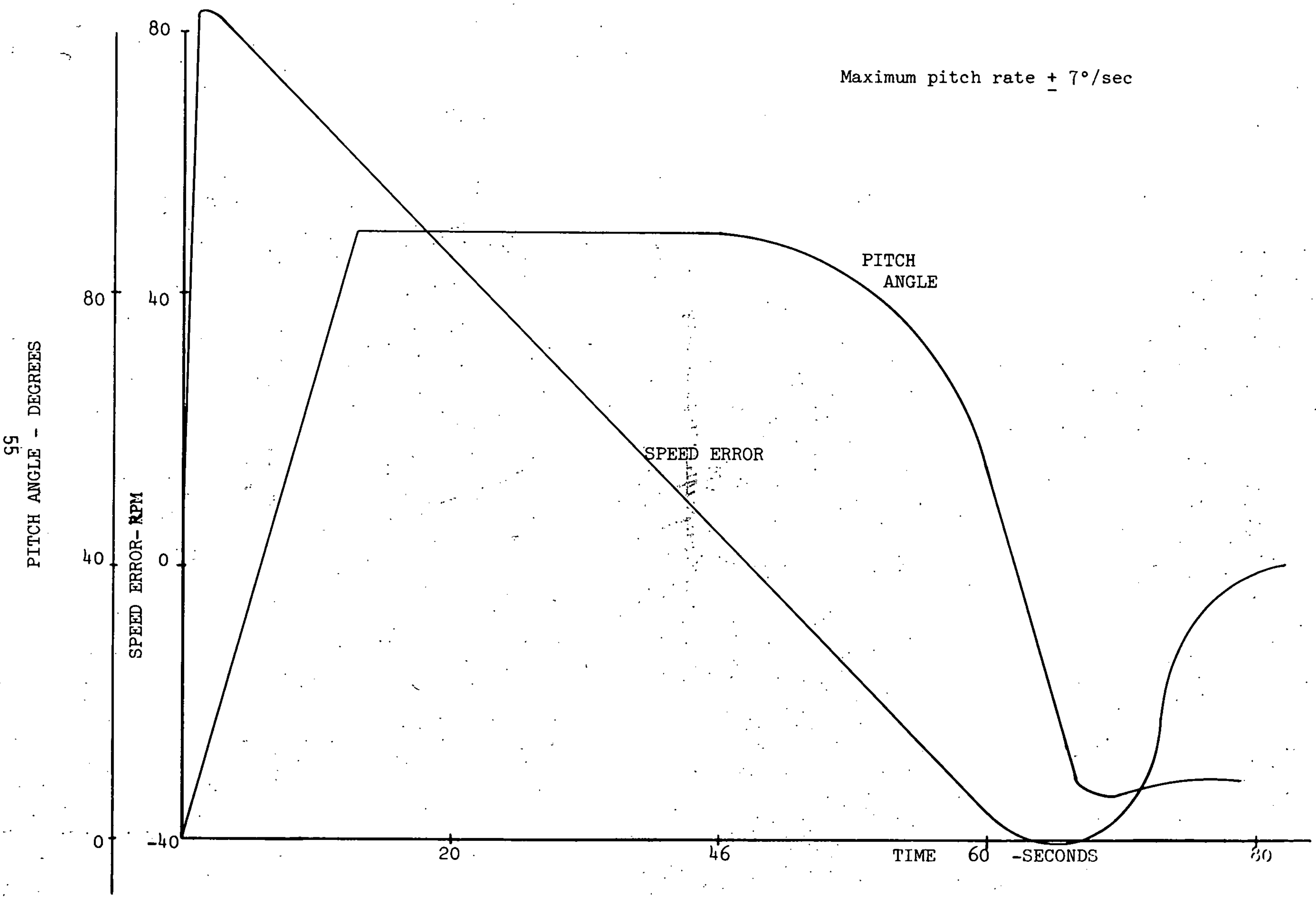


Fig. 20 LOAD LOSS FROM RATED LOAD, 1500 KW WTG

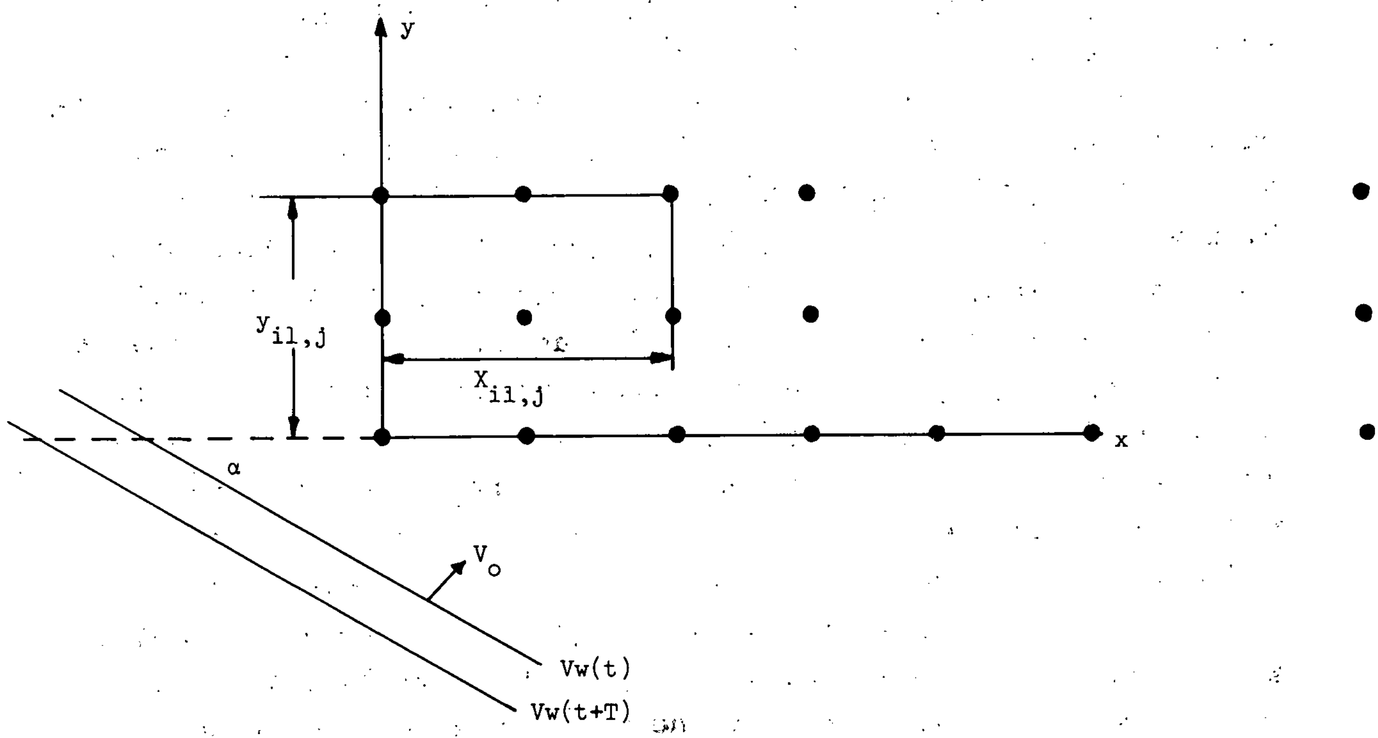


Fig. 21 WIND FARM CONFIGURATION

tain rotor rotation, is neglected in this model because wind profiles for such low wind speeds will not be considered due to the small effects on wind array power and thus the power system which the wind array is connected to.

This model of a single wind turbine generator also includes an inertia and damping term when the machine is operating and not in the shutdown-startup mode that avoids damage due to high wind speed. This inertia must be included in the lumped inertia parameter for the internal system HINT, and the mechanical power PMW(t) must be included as an input to this common inertia model along with mechanical shaft powers from all other machines in the internal system. The triggering of the shutdown-startup sequence when average wind speed is above 64 km/hr would cause the mechanical shaft power to become zero and a reduction of inertia HINT during the interval when average wind speed remained above 53 km/hr. The reduction in inertia, when turbine generation is lost due to the shutdown for high wind, may not be necessary if the wind turbine generation shutdown is a small percentage of the total generation in the system.

The wind speed profile $V_{ij}(t)$ at the i^{th} wind turbine generator in wind array j and, thus the mechanical shaft power PM_{ij} out of this generator, is a delayed version of the wind velocity profile $V_{ij}(t)$ and mechanical shaft power $PM_{ij}(t)$ for a reference generator i=1 in wind array j if:

(1) the wind velocity is assumed constant along straight line contours in the region where a wind array is located;

(2) the velocity of each straight line contour of constant wind velocity is the velocity of the wind front (V_o) and not the velocity of the wind at that location and time instant;

(3) the wind velocity contours are parallel and each have an angle α with the x axis of the wind farm as shown in Figure 21;

(4) reference generator i=1 in wind array j is always the first wind turbine generator affected by the front.

Based on the above assumptions, the wind velocity profile and generator shaft power at any generator in the array satisfies:

$$V_{ij}(t) = V_{1j}(t - T_{ij})$$

$$PM_{ij}(t) = PM_{1j}(t - T_{ij})$$

where T_{ij} is

(1) proportional to the distance

$$d_{il_j} = x_{il_j} \sin \alpha + y_{il_j} \cos \alpha$$

between the i^{th} generator in the array and the reference generator in the direction of movement of the wind front. The x_{il_j} and y_{il_j} are the distance between wind turbine generators i and 1 in the x and y axis, respectively;

(2) inversely proportional to wind front velocity V_o so that

$$T_{ij} = \frac{d_{il_j}}{V_o}$$

The assumption that wind speed is fairly constant over some straight line is true for short distances in a thunderstorm gust front. "The specific wind speed that would be experienced at any WTG in a cluster during the passage of a gust front would be very sensitive to the position relative to the location and path of the thunderstorm downdraft" [8]. The assumption that the wind speed is constant on a straight line that covers the extent of the wind array may not thus be true, but since a worst case analysis of the effects of wind turbine generation is desired, this assumption is made.

The assumption that the speed of each straight line contour is the speed of the front and not the wind speed at that straight line contour, is consistent with knowledge of thunderstorm gust fronts. The assumption that these straight line contours are parallel is certainly true in small regions, but is again assumed as a worst case condition in this analysis of the effects of wind turbine generation on governor control, automatic generation control, economic dispatch, and unit commitment strategies of a power system.

Straight line parallel contours are worst case wind thunderstorm gust fronts for the wind farm configuration chosen because the wind turbines are arranged in echelons normal to the motion of the thunderstorm front and, thus, the straight line constant wind speed contours will effect every WTG in an echelon, identically and simultaneously maximizing the power variations from the farm and the effect on the power system.

Suppose the siting patterns are not exactly in straight lines and not evenly spaced as in the wind array configurations considered in Part II. Then the analyses, which places constraints on the penetration of any echelon in a farm and the penetration of a farm formed by a set of WTG clusters affected by the wind front in the response time of spinning reserve requirement on the AGC, is still meaningful in assessing whether a particular set of WTG clusters will cause operating problems for a power system

4. MODEL AGGREGATION

The purpose of this section is

(1) to discuss the rationale for aggregation similar generation components (coal fired drum, oil fired drum, once through subcritical, once through supercritical, gas turbine, hydro turbine, boiling water reactor) performing a similar function (regulation, economic dispatch, base loaded);

(2) to discuss the assumptions needed for aggregation

and the resulting aggregated generating components in the power system model;

(3) to discuss the impacts of aggregation on economic dispatch and automatic generation control. In particular, this discussion included

   (a) a method for determining cost curves of aggregated units from the cost curves of a typical unit of a particular type performing a particular function

   (b) An analysis of the theoretical basis of the CUREMW/λ and λ/PG_j curves in the central and local dispatch offices when the cost curves for aggregated generators are quadratic and transmission losses are neglected.

4.1 Rationale and Assumptions for Aggregation

The rationale for aggregation is:

(1) to considerably reduce the computation and model data required to simulate the power system model

(2) to reduce the complexity of the model so that the contribution of each type of generating component performing each task (regulation, economic dispatch, base load) could be more easily analyzed. Hopefully, this base of analysis of the economic dispatch, automatic generation, control. and unit commitment will be an asset if increased wind penetration leads to operating problems.

The assumptions required to perform the aggregation are

(1) that the local dispatch offices of each member company are identical;

(2) that the dispatch from a single local dispatch office would be identical to that performed at the individual dispatch office so that only a single local dispatch office need be used;

(3) an aggregated generator component would respond

identically to the collective responses of the individual generators.

Although the local dispatch offices are not identical in the PJM system and the aggregated generator model will not respond exactly as the collective response of the generators it represents, the system model will be a reasonably accurate representation of the PJM system. The objective is to make this system model qualitatively similar to the PJM model so that the results obtained have validity for representative large interconnected systems.

The aggregated generation types that are to be under regulation, economic dispatch, and base load in this system model are given below.

BASE LOAD

Nuclear (BWR)
Hydro
Drum

ECONOMIC DISPATCH

Drum Oil (Large, More Economical)
Drum Coal (Large, More Economical)

REGULATING & ECONOMIC DISPATCH

Hydro
Gas
Drum Oil (Small, More Expensive)
Drum Coal (Small, More Expensive)
Once Through Oil Subcritical
Once Through Coal Supercritical

The choice of aggregated generator components performing each function was made based on the four unit commitment-economic dispatch schedules for the PJM system given in Appendix A and knowledge of power system operating practice.

Gas turbines and hydro turbines are very fast responding units and would be helpful in regulation. Although other units under regulation are also under economic dispatch, neither the gas turbine nor the hydro turbine are under economic dispatch in this simulation because

(1) gas turbines are very expensive to operate and would not generally be used for regulation but only as peakers. The inclusion of gas turbines for regulation has been discussed in some references [10] and are included in units for regulation due to their fast response and possible need to compensate for the fast changing power output from a wind array;

(2) although hydro turbines could be placed under economic dispatch [11], they are generally not dispatched based on economics because their base level of generation is generally based on

   (a) the hydraulic coupling requirement on hydro units that must supply sufficient water for cooling fossil or nuclear units downsteam

   (b) the run of the river in order to take advantage of all of the power available at any instant since none can be stored

   (c) unit commitment schedules that utilize the reservior in a manner that minimizes total system cost and maximizes system security over a daily or weekly time interval.

Once-through subcritical steam turbine generators are used for regulation if hydro units are unavailable since these once-through units are relatively fast responding compared to drum units. These once-through units will also be placed under economic dispatch since these units are generally inexpensive to operate and thus their level of generation should be based on economics. Both subcritical and supercritical once through units were included due to the differences in their responses. Small older drum steam turbine generators are also used for regulation and economic dispatch because they are faster responding and less economical than newer larger drum steam turbine generators. Both coal and oil fired drum units are included since both the fuel dynamics and the cost curves for the two units are different.

A coal and oil fired drum unit are the only unit types which are under economic dispatch but without regulation responsibility in the four unit commitment schedules supplied by Philadelphia Electric. Therefore, only an oil and a coal fired drum unit are placed under economic dispatch.

The generators that are base loaded are generally either very large economical units or peakers. Their control action is confined to governor response for frequency regulation. Since the frequency regulation on nuclear units affected by wind generation is important and since nuclear generation is a significant portion of base loaded generation, a boiling water reactor unit is included as a base loaded unit. A hydro unit is included as a base loaded unit because this unit may be useful for compensating for changes in wind turbine generation. An oil drum unit is included to represent all other generation that is base loaded. Note that the nuclear boiling water and gas turbine reactors are not under economic dispatch or regulation in this PJM system.

4.2 Description of the Automatic Generation Control Economic Dispatch for Aggregated Generators

Having explained the rationale for the selection of the aggregated units to be included in the model, the operation of the automatic generation control-economic dispatch strategy, shown in Figures 22 and 23, will be discussed for such an aggregated model. This description will differ from that in Sections 2.9 and 2.10 in that the emphasis here will be on analyzing the purpose of each function performed rather than just describing the functions. Moreover, this discussion will be particular to the single local dispatch office - aggregated generator system model rather than the individual local dispatch office-individual generator model used in the PJM system model

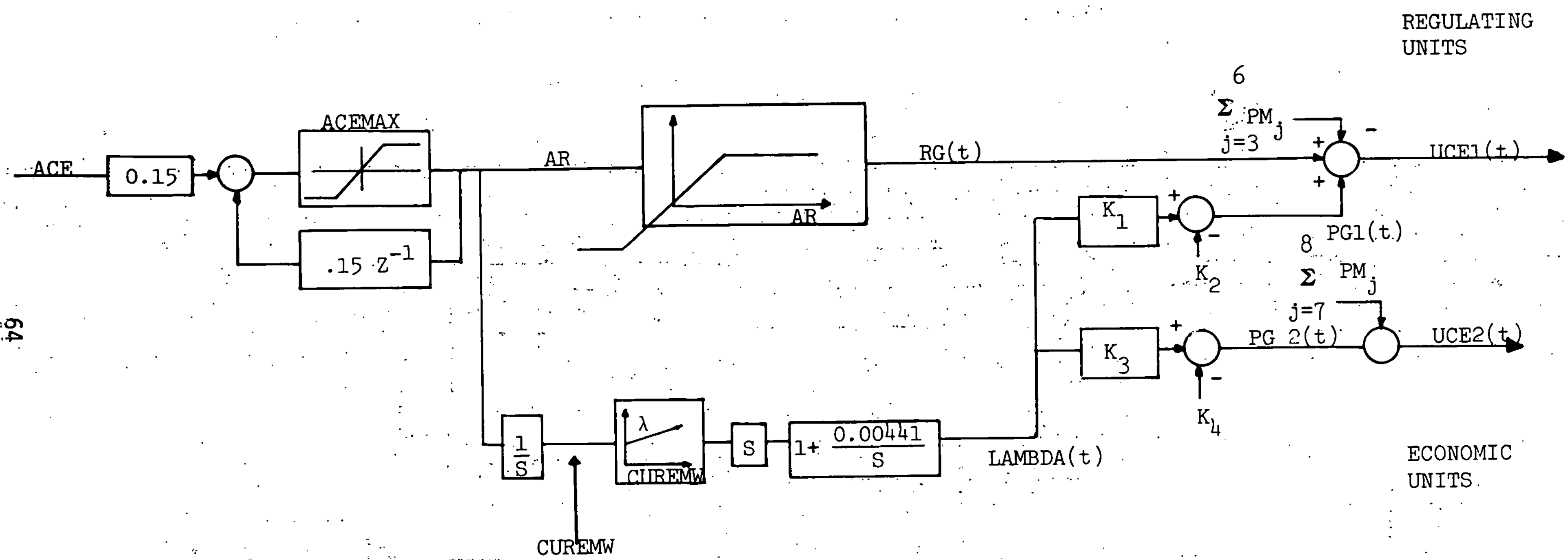


FIG. 22 BLOCK DIAGRAM OF TWO GENERATOR AGC-ED CONTROL

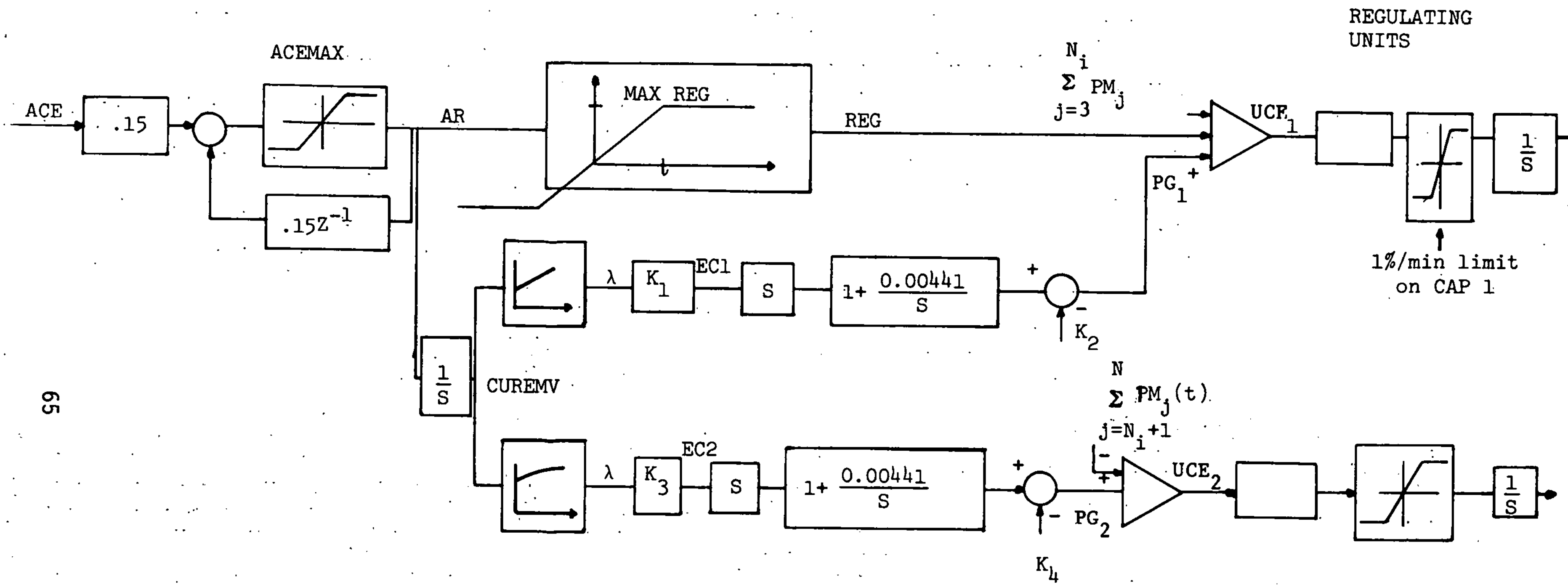


Fig. 23 SIMPLIFIED BLOCK DIAGRAM OF LOCAL AND CENTRAL DISPATCH OFFICE FOR THE AGGREGATED GENERATOR CASE.

[2]. Finally, the analysis of the automatic generation control-economic dispatch strategy will be separated as much as possible into an analysis of the regulation and an analysis of the economic dispatch tasks. The operation of the central dispatch office is analyzed first and then the local dispatch office.

The function of the central dispatch office is to compute the area control error ACE(t) and filter and process it to produce the area requirement signal AR(t) for regulation the LAMBDA(t) signal for economic dispatch. The area requirement is produced by low pass filtering ACE(t) to 0.16 rad/sec and magnitude limiting ACE(t) to ACEMAX. If ACE(t) is assumed bandlimited to 0.16 rad/sec then

$$AR(t) = \begin{cases} ACE(t) & ACE(t) \leq ACEMAX \\ \\ ACEMAX & ACE(t) > ACEMAX \end{cases} \tag{1}$$

This AR(t) is sent to the local dispatch office but is also further processed to produce LAMDA(t). The first step in producing LAMBDA (t) is to integrate AR(t) to produce

$$CUREMW(t) = CUREMW(0) + \int_0^t AR(\gamma)\, d\gamma \tag{2}$$

which is the part of the total internal load that is not base load. This CUREMW(t) signal produces a $\lambda(t)$ signal through the function

$$\lambda(t) = f_0(CUREMW(t)) \tag{3}$$

The form of this function will be described in the next section when the theoretical basis for the economic dispatch is analyzed.

This $\lambda(t)$ signal is then differentiated and put through a compensator with transfer function

$$G_c(S) = 1 + \frac{0.00441}{S} \tag{4}$$

to produce the LAMBDA(t) function sent to the local dispatch office.

The local dispatch office performs regulation and economic dispatch tasks using AR(t) and LAMBDA(t) respectively. The regulation command to each aggregated generator is

$$RG_j(t) = \begin{cases} \beta_j AR(t) & \beta_j AR(t) < MR_j \\ MR_j & \beta_j AR(t) \geq MR_j \end{cases} \tag{5}$$

where β_j is the participation factor for aggregated generator j and MR_j is maximum regulation permitted on aggregated generator j. The maximum regulation on aggregated generator j is

$$MR_j = \sum_{i=1}^{Nj} MR_{ij}$$

which is the sum of the maximum regulation of all N_j generators of type j in the particular unit commitment economic dispatch schedule used. The participation factor for aggregated generator j is then

$$\beta_j = \frac{MR_j}{MR} \tag{6}$$

where MR is the sum of the maximum regulation or all aggregated generators performing the regulation task.

$$MR = \sum_{j=1}^{6} MR_j \tag{7}$$

The aggregated generators chosen to perform regulation are

hydro turbine	(j=1)
gas turbine	(j=2)
oil fired drum	(j=3)
coal fired drum	(j=4)
oil fired subcritical once-through	(j=5)
coal fired supercritical once-through	(j=6)

The economic dispatch command to generators is

$$PG_j(t) = f_{ij}(LAMBDA(t)) \tag{8}$$

The generators performing the economic dispatch function are:

oil fired drum on regulation and economic dispatch (j=3)

coal fired drum on regulation and economic dispatch (j=4)

coal fired subcritical once-through unit on regulation and economic dispatch (j=5)

coal fired supercritical once-through unit on regulation and economic dispatch (j=6)

oil fired drum unit on only economic dispatch (j=7)

coal fired drum unit on only economic dispatch (j=8)

There are two aggregated generators (j=7,8) under economic dispatch that do not participate in regulation and there are two generators (j=1,2) under regulation that do not participate in economic dispatch. The following generators are base loaded and do not participate in either economic dispatch or regulation.

Nuclear (Boiling Water Reactor)	(j=9)
Hydro	(j=10)
Oil Fired Drum	(j=11)

The unit control for base loaded units (j=9,10,11) is

$$UC_j(t) = PS_j(t) \tag{9}$$

where PS_j for the base loaded units of each type are determined by summing the generation of all individual generators of that type that are base loaded from the unit commitment-economic dispatch data set chosen. The unit control signal is not modified by regulation (RG_i) or economic dispatch (PG_i).

The unit control error for the aggregated generators on strictly regulation (j=1,2) is

$$UCE_j(t) = RG_j(t) + UC_j(t) - PM_j(t) \qquad (10)$$

where UC_j and PM_j are the sum of the desired and actual measured generation levels of all units of this type respectively. The unit control signal (UC_j) is found from the unit commitment-economic dispatch data set chosen.

The aggregated generators strictly on economic dispatch (j=7,8) have unit control error

$$UCE_j(t) = PG_j - PM_j \qquad (11)$$

and the aggregated units under both regulation and economic dispatch (j=3,4,5,6) have unit control error

$$UCE_j(t) = PG_j(t) + RG_j(t) - PM_j(t) \qquad (12)$$

The units on regulation and economic dispatch (fossil fueled drum, fossil fueled once-through, hydro) units process the unit control error through a governor regulator to produce PS_j. The regulators are described in the generator models of Section 2 but are included in the local dispatch office subprogram.

The data for the aggregated generators under regulation (MR_j, β_j, $UC_j(0)$), base load ($UC_j(0)$), and under economic dispatch ($PG_j(0)$) are given in Table 9 for each unit commitment economic dispatch schedule. This data was abstracted from the unit commitment-economic dispatch schedules given to MSU by Philadelphia Electric Company.

UNITS	20,000 MW SYSTEM								4000 MW SYSTEM	
Regulations	MORNING PICKUP #1		MORNING PICKUP #2		SUMMER PEAK		EVENING LULL		EVENING DROP	
	MR_j(MW)	UC_j(MW)	MR_j(MW)	UC_j(MW)	MR_j(MW)	UC_j(MW)	MR_j(MW)	UC_j(MW)	MR_j(MW)	UC_j(MW)
J=1	50	800	0	0	36	44	0	0	0	0
J=2	0	0	0	0	0		0	0	0	0
J=3	65	2169	46	671	66	1828	106	1559	21.2	311.8
J=4	73	3006	64	1742	84	2850	17	380	3.4	76
J=5	0	0	0	0	0	0	0	0	0	0
J=6	0	0	8	195	0	386	17	868	3.4	173.6
Economic Dispatch	PG_j		PG_j		PG_j		PG_j		PG_j	
J=7	1260		816		1631		1427		285.4	
J=8	1413		375		2754		1246		249.2	
Base Loaded	UC_j		UC_j		UC_j		UC_j		UC_j	
J=9	500		2337		986		3807		761.4	
J=10	659		205		1113		0		0	
J=11	6925		9609		8894		10158		2031.6	

Table 9

Unit Committment Data for Aggregated Units

4.3 A Theoretical Basis for Economic Dispatch Using Aggregated Generator Models

The two objectives of this subsection are to

(1) analytically derive the functional relationships

$$\lambda(t) = f_o(\text{CUREMW}(t))$$

$$PG_j(t) = f_{ij}(\text{LAMBDA}(t))$$

based on knowledge of the cost curves

$$F_j(PG_j) = a_j + b_j(PG_j) + c_j(PG_j)^2 \qquad (13)$$

for each aggregated generator

(2) derive the form of the cost curves for these aggregated generators (13) from knowledge of the cost curves for typical individual generators of each type

$$F_{ij}(PG_{ij}) = a_{ij} + b_{ij}(PG_{ij}) + c_{ij}(PG_{ij})^2 \qquad (14)$$

The derivation of the functions $f_o(\ )$ and $f_{ij}(\ )$ uses the following nonlinear programming argument.

The economic dispatch problem can be stated formally as follows:

Determine the optimal generation PG_j^* that minimizes total generation cost

$$F(PG_3, PG_4, \ldots, PG_8) = \sum_{j=3}^{8} F_j(PG_j) \qquad (15)$$

given

$$F_j(PG_j) = a_j + b_j PG_j + c_j(PG_j)^2 \qquad (16)$$

where the sum of the generation on these units is contrained to equal the generation to be dispatched

$$\sum_{j=3}^{8} PG_j = CUREMW = LODEIN\text{-}PBASE \tag{17}$$

The transmission losses are neglected in this formulation and

$$PBASE = UC_1 + UC_2 + \sum_{j=9}^{11} UC_j$$

The Lagrange function for this optimization problem is

$$L(PG_3, PG_4, \ldots, PG_8, \lambda) = F(PG_3, PG_4, \ldots, PG_8) + \lambda(CUREMW - \sum_{j=3}^{8} PG_j)$$

The necessary conditions are

$$\frac{\partial L}{\partial PG_j} = \frac{\partial F(PG_j)}{\partial PG_j} - \lambda = 0 \tag{18}$$

$$= b_j + 2c_j PG_j - \lambda = 0$$

$$\frac{\partial L}{\partial \lambda} = CUREMW - \sum_{j=3}^{8} PG_j = 0 \tag{19}$$

Solving equation (18) for PG_j

$$PG_j(\lambda) = \frac{\lambda - b_j}{2c_j} \tag{20}$$

and substituting into (19), the multiplier λ becomes

$$\lambda = \frac{CUREMW + \sum_{j=3}^{8} \frac{b_j}{2c_j}}{\sum_{j=3}^{8} \frac{1}{2c_j}} \tag{21}$$

Noting that CUREMW(t) is not constant but a function of time

$$\lambda(t) = f_o(\text{CUREMW}(t))$$

$$= \frac{\text{CUREMW}(t) + \sum_{j=3}^{8} \frac{b_j}{2c_j}}{\sum_{j=3}^{8} \frac{1}{2c_j}}$$

The $\lambda(t)$ is processed through a differentiator and compensator to produce a signal LAMBDA(t) which is used to dispatch generation and thus

$$PG_j(t) = f_{ij}(\text{LAMBDA}(t))$$

$$= \frac{\text{LAMBDA}(t) - b_j}{2c_j} \qquad (23)$$

Thus, the functional relationships in the central and local dispatch offices have been derived.

The previous analysis neglected two considerations which are generally considered.

(1) loss in transmission of power

(2) minimum and maximum generation limits on each generator

$$P_{MIN_j} \leq PG_j \leq P_{MAX_j}$$

The losses in transmission will be neglected because

(1) they are sometimes (seldom) neglected even in large

utilities

(2) the inclusion of transmission losses would only affect total cost by about a few percent in practice and thus are small enough to be neglected in this study of operating problems which arise due to increases in wind penetration.

Minimum and maximum generation limits on aggregated generating units can be neglected because it is very unlikely given a good unit commitment that all generators of a particular type will be at minimum or maximum generation limits even if some of the generators being aggregated could be at one of these limits.

A second reason for ignoring the minimum and maximum limits on particular aggregated units is that the power system model will be simulated over one or two hours at most and the unit commitment schedule should be accurate enough over that interval so that all generators of a particular type will not hit maximum or minimum generation limits.

The level of generation for the hydro ($j=1$) and gas turbine ($j=2$) aggregated generators under regulation and for the base loaded aggregated generators is not affected by this economic dispatch strategy and are

(1) constrained to have initial generation levels equal to the sum of the generation of all generators of that type for the unit commitment-dispatch schedule chosen

(2) are adjusted according to present schedules which depend on the internal load (LODEIN) schedule.

The generations levels $PG_j(t)$ for aggregated generators under economic dispatch are not predetermined since the generation level $PG_j(t)$ at any time for these generators depends on the generation to be dispatched (2) which is proportional to LODEIN(t) - PBASE(t) where

$$PBASE(t) = (UC_1(t) + UC_2(t) + \sum_{j=9}^{11} UC_j(t))$$

Although the initial generation level $PG_j(0)$ for each aggregated generator under economic dispatch is known (Table 9) by adding the generation of all generators of that type from the particular unit commitment-dispatch schedule considered, the cost curve parameters $(a_j b_j c_j)_{j=3}$ for the aggregated generators that will result in those initial generation levels are unknown and must be determined.

The selection of the cost curve parameters must be based on

(1) knowledge of the initial cost per megawatt $\lambda(t)_{t=0}$ on the PJM system for the dispatch given in the particular unit commitment-dispatch schedule considered

(2) the assumption that the cost curves for aggregated generators is obtained based on the assumption that

  (i) there are N_j identical generators of type j each with cost curves

$$F_{ij}(PG_{ij})=a_{ij} + b_{ij}(PG_{ij}) + c_{ij}(PG_{ij})^2$$

  where a_{ij}, b_{ij} and c_{ij} are known.

(3) each of these N_j generators of type j will carry an equal share of the generation PG_j for any value of PG_j since they have identical cost curves

$$PG_{ij} = \frac{PG_j}{N_j} \tag{24}$$

(4) the cost for the aggregated generator of type j is the sum of the cost curves for the N_j individual identical generators of type j

$$F_j(PG_j) = \sum_{i=1}^{N_j} F_{ij}(PG_{ij}) \tag{25}$$

Noting that (a_{ij}, b_{ij}, c_{ij}) are identical for all $i=1,2...,N_j$ and substituting (24) into (25), the cost curve for aggregated generator of type j becomes

$$F_j(PG_j) = N_j a_{ij} + b_{ij}\left(\sum_{i=1}^{N_j} PG_{ij}\right) + c_{ij}\left(\sum_{i=1}^{N_j} PG_{ij}^2\right)$$

$$= N_j a_{ij} + b_{ij} PG_j + \frac{c_{ij}}{N_j} PG_j^2$$

so that the coefficients of the aggregated generator cost curve (13) can be expressed in terms of the coefficients of a typical generator cost curve as follows

$$a_j = N_j a_{ij}$$

$$b_j = b_{ij}$$

$$c_j = \frac{c_{ij}}{N_j}$$

The coefficients for typical generators of each type (j) were supplied by Philadelphia Electric along with their generator capacities and are given in Table 10.

The value of N_j and thus (a_j, b_j, c_j) will be determined from knowledge of $\{PG_j(0)\ a_{ij}, b_{ij}, c_{ij}\}_{j=3}$ and the initial cost per megawatt $\lambda(0)$ using the necessary conditions (18) as follows

$$b_j + 2c_j PG_j(0) = \lambda(0) \qquad (28)$$

Substituting (27) for b_j and c_j and solving

$$N_j = \frac{2c_{ij} PG_j(0)}{\lambda(0) - b_{ij}} \qquad (29)$$

UNITS	20000 MW SYSTEM																4000 MW SYSTEM			
	Summer Peak, $\lambda(0)$=60$/MW				Evening Lull $\lambda(0)$=17				Morning Pickup #1, $\lambda(0)$=35$/MH				Morning Pickup #2, $\lambda(0)$=35$/MW				Evening Drop $\lambda(0)$=17			
J	$PG_j(0)$	b_{ij}	b_j	c_j	$PG_j(0)$	b_{ij}	b_j	c_j	$PG_j(0)$	b_{ij}	b_j	c_j	$PG_j(0)$	b_{ij}	b_j	c_j	$PG_j(0)$	b_{ij}	b_j	c_j
3	1828	4.5455	4.5455	15.16×10^{-3}	1559	4.5455	4.5455	3.99×10^{-3}	2169	4.5455	4.5455	7.02×10^{-3}	671	4.5455	4.5455	20.269×10^{-3}	311.8	4.5455	4.5455	19.95×10^{-3}
4	2850	4.5833	4.5833	9.722×10^{-3}	380	4.5833	4.5833	16.337×10^{-3}	3006	4.5833	4.5833	5.059×10^{-3}	1742	4.5833	4.5833	8.73×10^{-3}	76	4.5833	4.5833	81.685×10^{-3}
5	--	--	--	--	--	--	--	--	0	--	--	--	--	--	--	--	--	--	--	--
6	386	4.4	4.4	72.02×10^{-3}	868	4.4	4.4	7.258×10^{-3}	0	--	--	--	195	4.4	4.4	78.48×10^{-3}	173.6	4.4	4.4	36.29×10^{-3}
7	1631	4.6154	4.6154	16.978×10^{-3}	1427	4.6154	4.6154	4.399×10^{-3}	1260	4.6154	4.6154	12.057×10^{-3}	816	4.6154	4.6154	$18x62 \times 10^{-3}$	285.4	4.6154	4.6154	21.695×10^{-3}
8	2754	4.6429	4.6429	10.05×10^{-3}	1246	4.6429	4.6429	4.958×10^{-3}	1413	4.6429	4.6429	10.742×10^{-3}	375	4.6428	4.6428	40.47×10^{-3}	249.2	4.6429	4.6429	24.79×10^{-3}

Table 10

and

$$a_j = \frac{2a_{ij}c_{ij}}{\lambda(0)-b_{ij}} PG_j(0)$$

$$b_j = b_{ij} \tag{30}$$

$$c_j = \frac{\lambda(0)-b_{ij}}{2PG_j(0)}$$

Values of a_j, b_j and c_j are given in Table 10 for generators (j=3,4..,8) for each economic dispatch-unit commitment condition.

5. ANALYSIS OF THE DYNAMIC PERFORMANCE OF THE AGC-ED STRATEGY

An analysis of the dynamic performance of the AGC-ED strategy developed in the previous section for aggregated generating units is now analyzed to determine if it meets NAPSIC response requirements and typical spinning reserve requirements so that its use in assessing operating problems associated with wind power variations when wind array penetration increases can be justified.

The dynamic performance of the automatic generation control-economic dispatch can not be analyzed with eight aggregated generators controlled by this strategy except by simulation. However, some understanding of the structure and design of this automatic generation control-economic dispatch strategy for aggregated generating units developed in the previous section can be accomplished if the eight aggregated generators under economic dispatch and regulation are further aggregated to produce a single aggregated generator under regulation and economic dispatch and a single aggregated generator under only economic dispatch as shown in Figure 22.

The analysis necessary to further aggregate this system model to this two aggregated generator model will be undertaken first. Then performance specifications on the AGC-ED strategy will then be discussed. Finally the AGC-ED strategy for this two generator model will be shown to meet these performance specifications. A brief discussion of the design of this AGC-ED strategy is then made.

The central dispatch office model does not change when the eight generators on economic dispatch and regulation are aggregated to form two generators. The local dispatch office does change considerably. The regulation on the single aggregated generator performing regulation is

$$RG(t) = \begin{cases} AR(t) & AR(t) \leq MR \\ MR & AR(t) > MR \end{cases}$$

since

$$RG(t) = \sum_{j=1}^{6} RG_j(t) = \begin{cases} \sum_{j=1}^{6} \beta_j AR(t); & AR(t) \leq MR \\ MR & ; \quad AR(t) > MR \end{cases}$$

and

$$\sum_{j=1}^{6} \beta_j = 1$$

The economic dispatch command to the aggregated generators #1 and #2 is

$$\begin{aligned} PG_1(t) &= \sum_{j=3}^{6} PG_j(t) \\ &= \sum_{j=3}^{6} \left(\frac{LAMBDA(t) - b_j}{2c_j} \right) \\ &= \left(\sum_{j=3}^{6} \frac{1}{2c_j} \right) LAMBDA(t) - \sum_{j=3}^{6} \frac{b_j}{2c_j} \\ &= K_1 \quad LAMBDA(t) - K_2 \end{aligned}$$

$$PG_2(t) = \sum_{j=7}^{8} PG_j(t)$$

$$= \sum_{j=7}^{8} \left(\frac{LAMBDA(t)-b_j}{2c_j}\right)$$

$$= \left(\sum_{j=7}^{8} \frac{1}{2c_j}\right) LAMBDA(t) - \sum_{j=7}^{8} \frac{b_j}{2c_j}$$

$$= K_3\, LAMBDA(t) - K_4$$

where

$$K_1 = \sum_{j=3}^{6} \frac{1}{2c_j} \qquad K_2 = \sum_{j=3}^{6} \frac{b_j}{2c_j}$$

$$K_3 = \frac{1}{2c_7} + \frac{1}{2c_8} \qquad K_4 = \frac{b_7}{2c_7} + \frac{b_8}{2c_8}$$

The local and central dispatch offices for this two aggregated generator model is thus shown in Figure 21. Since the derivative and compensator blocks are linear operators, the economic dispatch can be separated into separate paths to aggregate generators #1 and #2 by moving gain block K_1 and K_3 through the compensator and differentiator blocks as shown in Figure 22. The commands EC1 and EC2(t) are

$$EC1 = K_1\left(\frac{CUREMW(t) + \sum_{j=3}^{8} \frac{b_j}{2c_j}}{\sum_{j=3}^{8} \frac{1}{2c_j}}\right)$$

$$= K_1 \left(\frac{CUREMW(t) + (K_2+K_4)}{K_1 + K_3} \right)$$

$$= \frac{K_1}{K_1+K_3} \left(CUREMW(t) + K_2+K_4 \right)$$

$$EC2(t) = K_3 \left(\frac{CUREMW(t) + \sum_{j=3}^{8} \frac{b_j}{2c_j}}{\sum_{j=3}^{8} \frac{1}{2c_j}} \right)$$

$$= \frac{K_3}{K_1+K_3} \left(CUREMW(t) + K_2+K_4 \right)$$

The purpose of this section is to analyze the dynamic performance of this automatic generation control strategy. This can be most easily done by assuming steady state conditions are prevailng.

$$ACE(0) = 0 = RG(0)$$

$$UCE_1(0) = \sum_{j=3}^{6} PG_j(0) - \sum_{j=3}^{6} PM_j(0) + RG(0) = 0$$

$$UCE_2(0) = \sum_{j=7}^{8} PG_j(0) - \sum_{j=7}^{8} PM_j(0) = 0$$

and then insert a step change in the area control error

$$ACE(t) = \begin{cases} \Delta P & t \geq 0 \\ 0 & t < 0 \end{cases}$$

The unit control error signals expressed as Laplace transforms are

$$UCE_1(S) = \left[\sum_{j=3}^{6} PG_j(S) - \sum_{j=3}^{6} PM_j(S)\right] + RG\ (S)$$

$$UCE_2(S) = \left[\sum_{j=7}^{8} PG_j(S) - \sum_{j=7}^{8} PM_j(S)\right]$$

where

$$RG(S) = \begin{cases} \dfrac{\Delta P}{S} & |\Delta P| < MR \\ \dfrac{MR}{S} & |\Delta P| > MR \end{cases}$$

$$\left[\sum_{j=3}^{6} PG_j(S) - \sum_{j=3}^{6} PM_j(S)\right] = \frac{K_1}{K_1+K_3}\left[1 + \frac{0.00441}{S}\right]\left[S\Delta CUREMW(S)\right]$$

$$\left[\sum_{j=7}^{8} PG_j(S) - \sum_{j=7}^{8} PM_j(S)\right] = \frac{K_3}{K_1+K_3}\left[1 + \frac{0.00441}{S}\right]\left[S\Delta CUREMW(S)\right]$$

where

$$S\Delta CUREMW(S) = \begin{cases} \dfrac{\Delta P}{S} & |\Delta P| < ACEMAX \\ \dfrac{ACEMAX}{S} & |\Delta P| > ACEMAX \end{cases}$$

and where $S\Delta CUREMW(S)$ is the Laplace transform of

$$\frac{d}{dt}\Delta CUREMW(t)$$

Substituting the above terms into $UCE_1(S)$ and $UCE_2(S)$ and performing the inverse Laplace transform yields

$$UCE_1(t) = \begin{cases} \Delta P + \dfrac{K_1}{K_1+K_3}\ \Delta P\ (1+0.00441t) & : \Delta P < MR < ACEMAX \\ MR + \dfrac{K_1}{K_1+K_3}\ \Delta P\ (1+0.00441t) & : MR < \Delta P < ACEMAX \\ MR + \dfrac{K_1}{K_1+K_3}\ ACEMAX\ (1+0.00441)t & : MR < ACEMAX < \Delta P \end{cases}$$

$$UCE_2(T) = \begin{cases} \dfrac{K_3}{K_1+K_3} \Delta P \, (1 + 0.00441t) & : \Delta P < ACEMAX \\ \dfrac{K_3}{K_1+K_3} ACEMAX \, (1 + 0.0441t) & : ACEMAX < \Delta P \end{cases}$$

The design of this AGC-ED control is based on the following NAPSIC requirements

(1) Area Control Error (ACE) should cross zero once every ten minutes.

(2) Area Control Error should have a ten minute average less than 45 MW for an interconnection the size of PJM.

(3) Area Control Error should be limited to instantaneous values less than 135 MW for a system of PJM's size.

The difficulty in reaching these performance levels has shown the need to simulate the system and to develop new control algorithms.

General spinning reserve requirements used on NEPOOL, which are representative, are that

(1) generation equal to the capacity of the largest generator be available within 10 minutes

(2) an additional generation equal to half the capacity of the largest generator be available in the next twenty minutes so that one and one half times the capacity of the largest generator must be available in the first thirty minutes after the contingency.

If we consider that the largest generator on PJM is 1000 MW so that ΔP=1000 and that for the unit commitment-economic dispatch in this case

$$ACEMAX = 200 \text{ MW}$$

$$MR = 180 \text{ MW}$$

the power dispatched in t = 600 sec (10 min) is

$$UCE_1(t) + UCE_2(t) = MR + ACEMAX(1+0.00441t)_{t=600} = 912 \text{ MW}$$

An additional 100 MW is taken up directly by governor action in the PJM system for this 1000 MW change in load due to the drop in system frequency and the fact that

$$\frac{H_{PJM}}{H_{USA}} = \frac{B_{PJM}}{B_{USA}} = .1$$

Thus, the requirement that the system will be able to pick up the generation of the largest unit within ten minutes is certainly met. The selection of the gain for the proportional (1) and reset (0.00441) components in the economic path and the gain of the regulating signal (1) are chosen because

(1) the proportional gain on the regulating signal be 1 so that the filtered ACE is the exact signal put to the units performing regulation so that the generation will be AR at the response time of the unit.

(2) the proportional gain of the economic dispatch signal must be identical to that of the regulating signal so that the adjustment of power to the most economic units will be based on the actual power in the system and not some proportion of it.

(3) the gain of the reset signal then determines the rate at which the system will be able to respond to a loss of generation and is chosen based on the requirement that for (ACEMAX=200, MAXREG=180) the capacity of the largest unit can be obtained in 10 minutes.

The analysis shows that the AGC-ED strategy developed for aggregated generating units should meet typical spinning reserve requirements as well as the NAPSIC performance requirements. It should be noted that NAPSIC performance requirements are violated occassionally for severe contingencies but are guidelines for good performance on any system.

The AGC-ED strategy developed for these aggregated generator units and based on the PJM strategy should be quite adequate for analyzing operating problems that might exist due to wind power variation as wind array penetration increases. The study of worst case wind power variation and its affects on this AGC-ED are analyzed in PART II of this report.

6. CONCLUSIONS

Part I of this research project, documented in this report, develops and justifies the models used in this research investigation of the operating problems associated with wind power variation on a large utility as wind array penetration increases. Thus, a model of the response of a single WTG in an array to a thunderstorm front and a model of the response of any wind farm, composed of WTG clusters which are affected by this thunderstorm gust front in the time frame of spinning reserve requirements on automatic generation control response are developed. The model of the single WTG uses a static nonlinear model to relate wind speed variations to mechanical power variations out of the wind turbine into the generator. The shutdown-startup sequence controls on blade pitch and rotor speed, which occur when excessive and sustained high wind speeds are present, is also included in the WTG model since a thunderstorm front will typically trigger such a shutdown-start-up sequence. A model of a WTG array is developed based on the assumption that every WTG experiences the same wind speed profile but delayed depending upon its position with respect to the WTG that first experiences the changes in speed for a thunderstorm front.

A dynamic model of a power system which is capable of being used to analyze operating problems of a typical automatic generation control-economic dispatch strategy, is also developed. The generating unit models, external system model, and automatic generation control-economic dispatch strategy model are developed.

A method for aggregating similar generating units (hydro, gas turbine, boiling water reactor, supercritical steam turbine, oil drum steam turbine, coal drum steam turbine) performing similar functions (base loaded, economic dispatch, regulation) is developed. This aggregation method is developed to reduce computer simulation cost and to facilitate analysis of operating problems on a particular type of unit performing a similar function. The choice of units to be aggregated and included in the simulation, the development of fuel cost curves for aggregated units based on fuel cost curves of typical units of that type, and the modification of the automatic generation control-economic dispatch to accomodate aggregated units is discussed.

The performance of this aggregated AGC-ED strategy is analyzed in order to show that it is satisfactory for assessing operating problems associated with wind power variation on a large utility as the wind array penetration increases. It is shown this AGC-ED strategy for aggregated units will meet normal spinning reserve and NAPSIC performance requirements.

Section 1:

1. SUMMARY OF PART II

The objectives of the work reported in section 2 of this part are

(1) to determine a theoretical worst case wind farm based on the maximum width of a thunderstorm front, the minimum distance between WTGs, the maximum distance a thunderstorm can travel in the time frame of the spinning reserve requirements on automatic generation control (10 minutes)

(2) to develop a practical worst case coastal and midwestern wind farm configurations based on the above theoretical worst case farm

(3) to determine a worst case storm front

(4) to determine via simulation the worst case from a single WTG exposed to a worst case storm front including the shutdown startup sequence

(5) to determine through simulation the worst case power variation record for the coastal and midwestern farm configurations for the worst case storm front

The objectives of the work reported in section 3 are

(1) to determine a maximum penetration per echelon that will keep wind power variation rate less than the power system response capability. Show that this echelon penetration will decrease slightly if the rate of change of the wind speed on the thunderstorm gust front leading edge outflow increases or if the echelons are spaced closely enough so that echelon responses due to this leading edge outflow would occur simultaneously. It is also shown that an echelon can be interpreted as all generation in a strip 25 mi wide spaced 0.416 mi for a typical thunderstorm front

(2) to determine a maximum penetration of WTGs in an area, called a farm, that could be affected by a thunderstorm front in the time frame of spinning reserve re-

quirements of automatic generation control so that AGC response rate is not exceeded by wind power variation from WTGs in such an area.

The objectives of section 4 are

(1) to show that the AGC regulation becomes saturated and thus cannot meet NAPSIC performance requirements whenever the total power generation change in an interval due to simultaneous load and storm induced WECS generation changes exceed the system spinning reserve requirement for that interval. This operating problem can be more frequent than one due to typical loss of generation contingencies since the problem appears when storm fronts pass thru arrays during morning pickup or evening dropoff.

(2) to show that increasing spinning reserve margins, which are set based on a study of system reliability that includes WECS generation, could alleviate this AGC regulation problem.

(3) to show that changes in generation mix to include higher percentages of fast responding generation (hydro, gas turbines) can have a significant effect on AGC regulation response to WECS generation changes when regulation is not in saturation.

(4) to show that cycling of nuclear units on governor frequency regulation can be severe when a storm front passes through a farm where several echelons have 50 WTGs, which is the maximum number that can be affected in any echelon by a single thunderstorm front. This problem would not appear if the generation capacity of each echelon were not large enough to cause frequency oscillations that exceed governor deadband of the generators in the system.

Section 2: WORST CASE POWER VARIATION FROM WIND ARRAYS

The specific tasks required to analyze worst case power variation out of a wind farm include

(1) a description of a theoretical worst case wind farm and a worst case storm front

(2) description of a worst case coastal and midwestern plains wind farm configurations based on the theoretical worst case wind farm configuration

(3) a description of a single WTG including its operation during the shutdown-startup sequence

(4) a description and analysis of the worst case power variation out of both coastal and midwestern plains wind farm configurations due to a worst case storm front.

The theoretical worst case farm and the coastal and midwestern farm configurations, which are chosen to produce worst case power variations due to a worst case storm front on frequency regulation and automatic generation control, are based on the following assumptions:

(1) that the initial wind speed before the storm front appears is 13 km/hr which is the cut in velocity of the MOD-1 machine. This is to achieve maximum power generation change out of each WTG,

(2) that the maximum width of any single thunderstorm front is approximately D_0 miles. The parameter D_0 is chosen as 25 mi. which is typical for Michigan. Other values would be used for other regions.

(3) that the minimum separation distance between WTG's in an echelon is to assure minimum loss of efficiency in a farm due to turbulence. This spacing constraint is taken as 0.57 mi for a 1.5 MW, MOD-1 machine;.

(4) that site availability constraints due to legal, environmental, and cost factors are negligible

(5) that wind velocity doesn't decrease between adjacent coastal echelons

(6) the maximum length of any midwestern farm of WTG

clusters which will affect AGC in the time frame associated with spinning reserve requirements (10 minutes) is 1/6 Vo for a thunderstorm front with frontal velocity Vo.

The analysis of farm or echelon penetration constraints in Section 3 and the investigation of operating problems due to WECS generation changes in Section 4 are both based on the implicit assumption that no two thunderstorms will occur simultaneously to affect two entirely separate areas containing WTG clusters at the same time. This assumption is justified because the likelihood of thunderstorms in two wind farms is similar to the double contingency that the two largest generators in the system will be lost simultaneously. Thus, the above assumptions can be used to define a theoretical worst case farm that can be treated as a single equivalent generator in terms of

(1) setting echelon and farm penetration constraints to keep power rate variations from this equivalent generator below response rate of the systems AGC, economic dispatch, and governor frequency regulations
(2) investigating operating problems in AGC, economic dispatch or frequency regulation due to thunderstorm induced WECS generation changes even if the penetration constraints are observed

It should be noted that this equivalent generator, which will be defined here as a wind farm, is composed of all WTG clusters that are included in a strip 25 miles wide and 1/6 Vo miles deep in the direction of front movement. The length of the farm (1/6 Vo) is set so that the generation of this farm could be interpreted in terms of the ten minute spinning reserve margin for a system. The length of an area containing WTG clusters could be longer than 1/6 Vo. Even though penetration level constraints were determined based on the above definition, the penetration constraint derived will be shown to also apply to any general wind farm. This is defined as all WTG clusters in a strip 25 miles wide and the entire length of the continuous area containing WTG clusters in the direction of movement of the front.

An echelon of WTGs is initially defined to be all WTGs in a straight line normal to the path of the front and a echelon farm penetration constraint (that restricts the power variation rate from an echelon be less than power system response rate capability) is developed based on this definition. Later this penetration constraint will be shown to apply to the <u>general definition of an echelon</u>, where all WTGs that respond simultaneously to the leading edge outflow of a storm front are considered an echelon and the echelon penetration constraint will be applied to any such general echelon.

The theoretical worst case wind farm based on assumption 2, 3 and 6 above is now developed. The theoretical worst case farm configuration for this 25 mi wide 5 mi long area for a 30 mph thunderstorm front is composed of 400 WTGs arranged in nine echelons of 45 WTG each where every WTG is spaced 0.57 miles from every other WTG in both latitudinal and longitudinal directions. The number of WTGs in an echelon is based on the maximum width of a thunderstorm front and the minimum spacing between adjacent WTGs. The number of echelons and the maximum distance the leading edge of a thunderstorm front, with front velocity Vo=30 mph can travel in the time frame of spinning reserve requirements on automatic generation control (10 minutes).

The worst case WTG array configuration for a coastal site assuming a worst case thunderstorm front, given in Figure 24, shows a 0.5 mi spacing between the 50 generators in each echelon and a 2 mile separation between the the two echelons. This 0.5 mi separation between WTGs in an echelon is based on turbulence avoidance. The number of generators in an echelon (50) is then based on the assumed maximum width of the thunderstorm gust front (25 mi) and the minimum spacing between WTGs for turbulence avoidance. The 2.0 mile spacing was used rather than 0.57 miles (even the smaller spacing would have placed more stringent requirements on frequency regulation

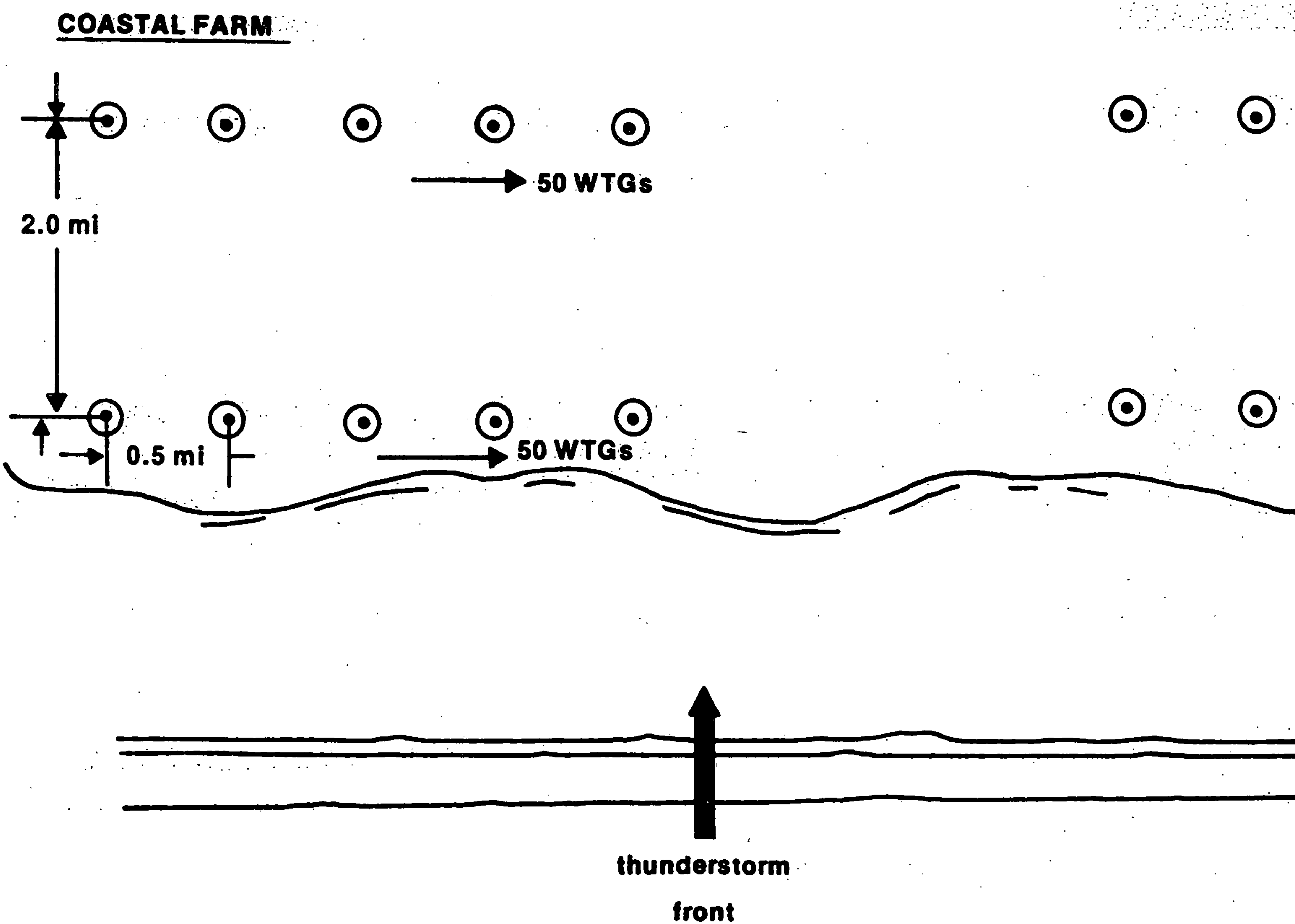


Figure 24 COASTAL FARM CONFIGURATION

and generation control performance) because the penetration limitation on any echelon to avoid exceeding power system response rate capability is easier to analyze for the 2.0 mile spacing since the responses on one echelon will not overlap the response of any other echelon for this thunderstorm front used. The number of echelons is restricted due to the decrease in wind speed as the distance from the coast increases. The actual midwestern plains farm configuration, shown in Figure 25 is composed of 10 echelons with 10 WTG's in each echelon and a 0.7 mi spacing between any two WTGs in both longitudinal and latitudinal directions. It should be noted that for the practical worst case midwestern farm

(1) only two WTGs are in an echelon rather than a maximum of forty-five

(2) only eight echelons of the ten echelons are going to affect AGC response in any one time frame (10 minutes) for spinning reserve requirements.

The worst case wind front used is one that assumes a 13 km/hr average wind speed before the thunderstorm front appears. The thunderstorm front will then increase generation to maximum values (1.5 MW) on each generator as the front passes through and the wind speed reaches 26 km/hr. The 13 km/hr wind speed before the front arrives is chosen so that each WTG has a maximum (1.5 MW) change in generation as the thunderstorm front moves through. If the wind speed before the thunderstorm gust front arrives is greater than 13 km/hr, this thunderstorm gust front would have less severe effects on power variation and would not be considered worst case. The following parameters are important for any worst case storm front.

The distance D is the distance in miles from the very leading edge of the outflow to a point internal in this outflow where wind speed first reaches a wind speed sufficient for maximum generation on the WTG. The velocity Vo is the front velocity at which the entire thunderstorm front moves.

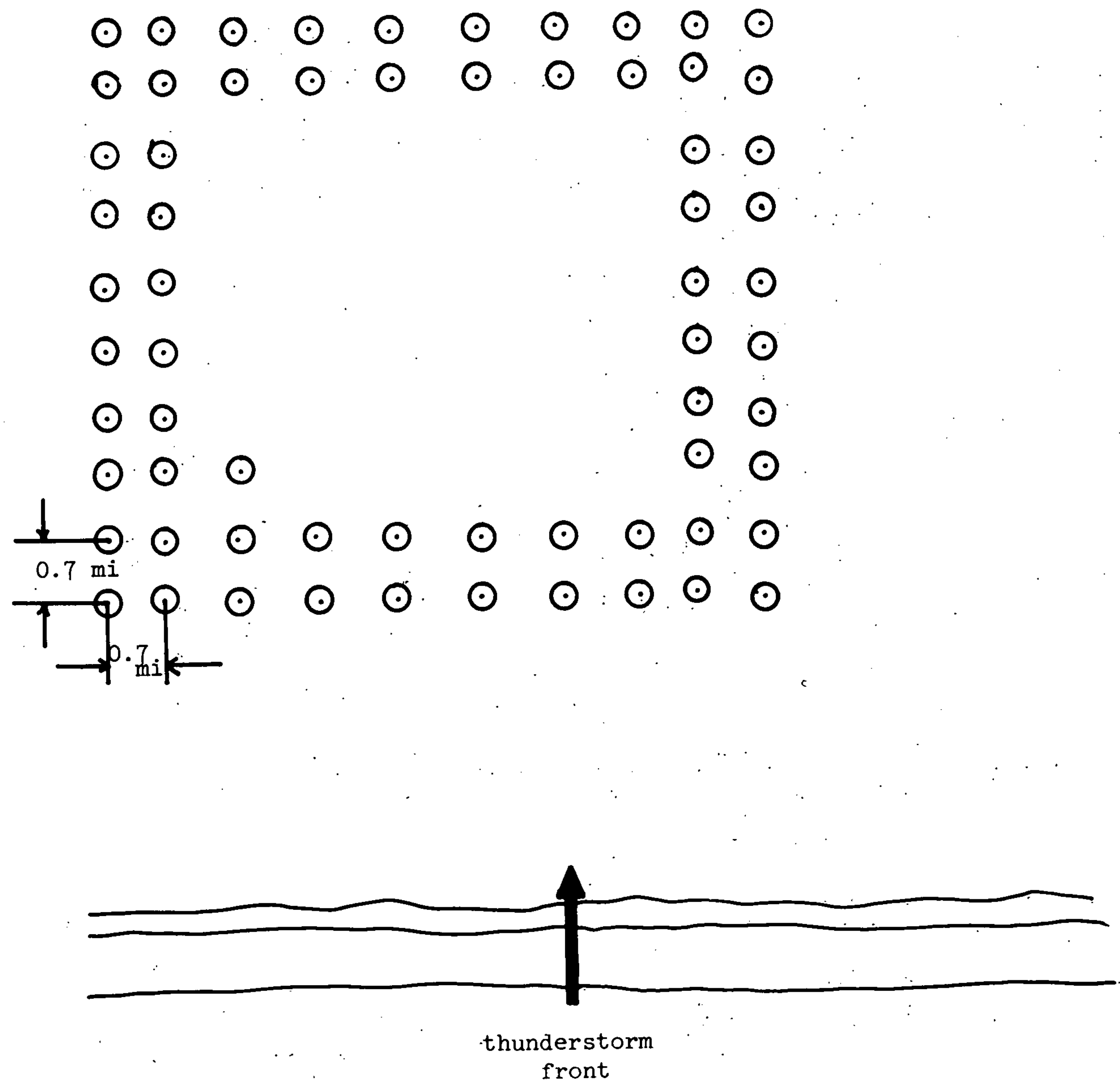


Figure 25 MIDWESTERN FARM CONFIGURATION

The wind speed profile, the resultant power out of a single WTG due to this wind speed profile, and the changes in blade pitch angle and blade rotational speed that occur during the shutdown-startup sequence when the trailing edge of the thunderstorm front passes each WTG, are now analyzed. The wind speed profile for the thunderstorm front for the first echelon of the farm and the power variation out of the farm are plotted in Figure 26C and 26D and 27C and 27D for the coastal and midwestern plain wind farm configurations, respectively. The wind speed profile shows an immediate increase from 8 km/hr to 80 km/hr in approximately the first 200 seconds as the leading edge of the outflow of the thunderstorm front passes over a particular WTG. The wind speed drops back after the leading edge of the outflow passes and then increases again and is sustained at this high level as the trailing edge inflow moves over the WTG site.

This rapid increase in wind speed for the leading edge of the thunderstorm front causes the power output of every WTG in the echelon, which simultaneously experiences this change in wind speed, to increase from zero to 1.5 MW in fifty seconds which is the time interval that it takes wind speed to increase from 13 km/hr to 26 km/hr, the speed at which the WTG achieves maximum generation. The ramp change in generation as the leading edge outflow passes through each echelon is observed in Figure 26D and 27D for the coastal and midwestern plains farms. The generation in each echelon does not decrease as the leading edge outflow passes and the wind speed decreases due to blade pitch angle adjustment and the fact wind speed stays above 26 km/hr. The power level out of each generator in each echelon is thus maintained constant at maximum levels until the trailing edge inflow passes where wind speeds are high enough and sustained long enough so that average wind speed out of the one minute filter for the i^{th} generator in the j^{th} farm $\hat{V}_{ij}(kT)$ surpasses 64 km/hr at kT = 650 seconds after the leading edge initially hits that echelon.

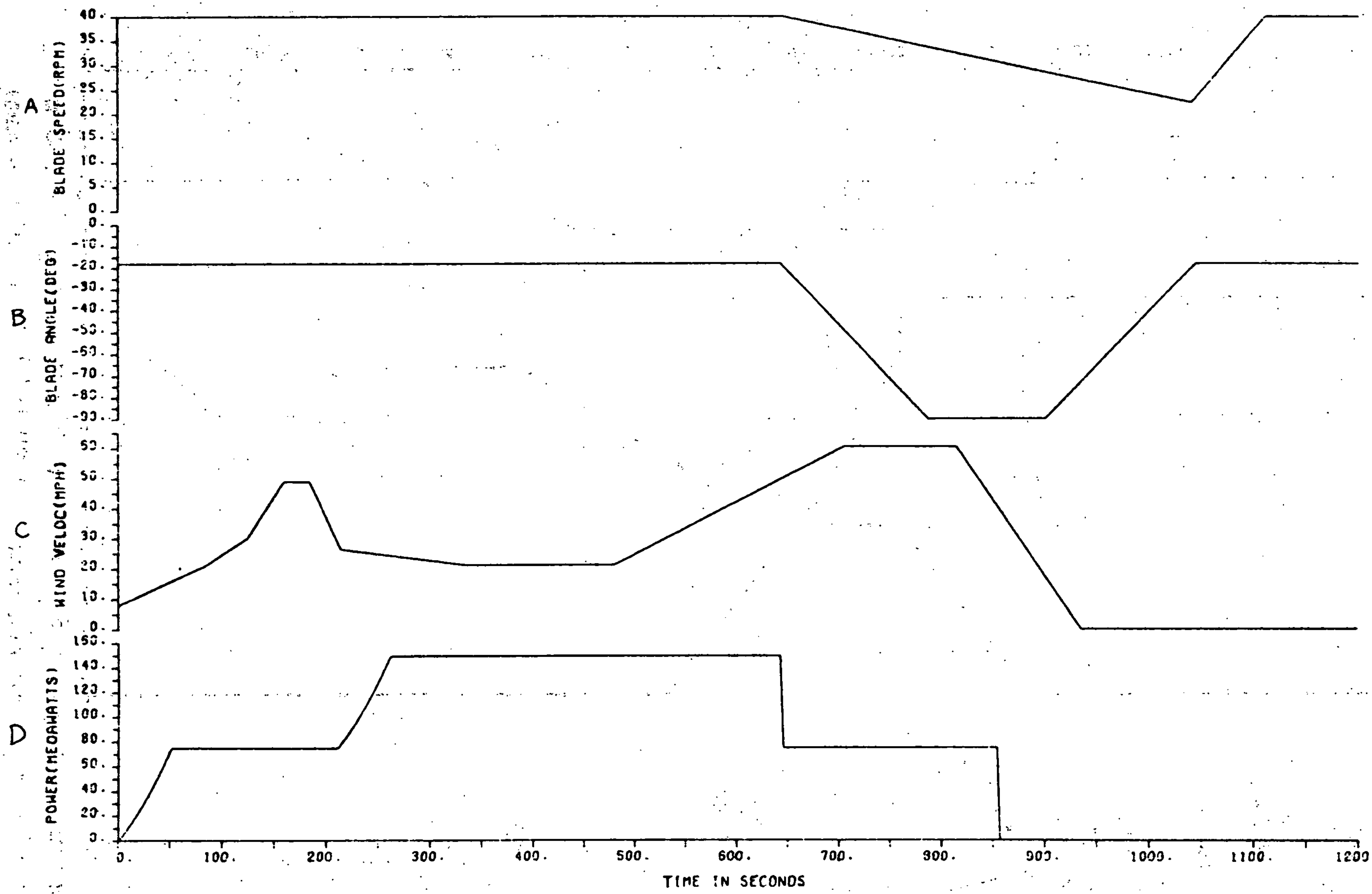


Figure 26 Simulation of Coastal Farm for a Thunderstorm Front

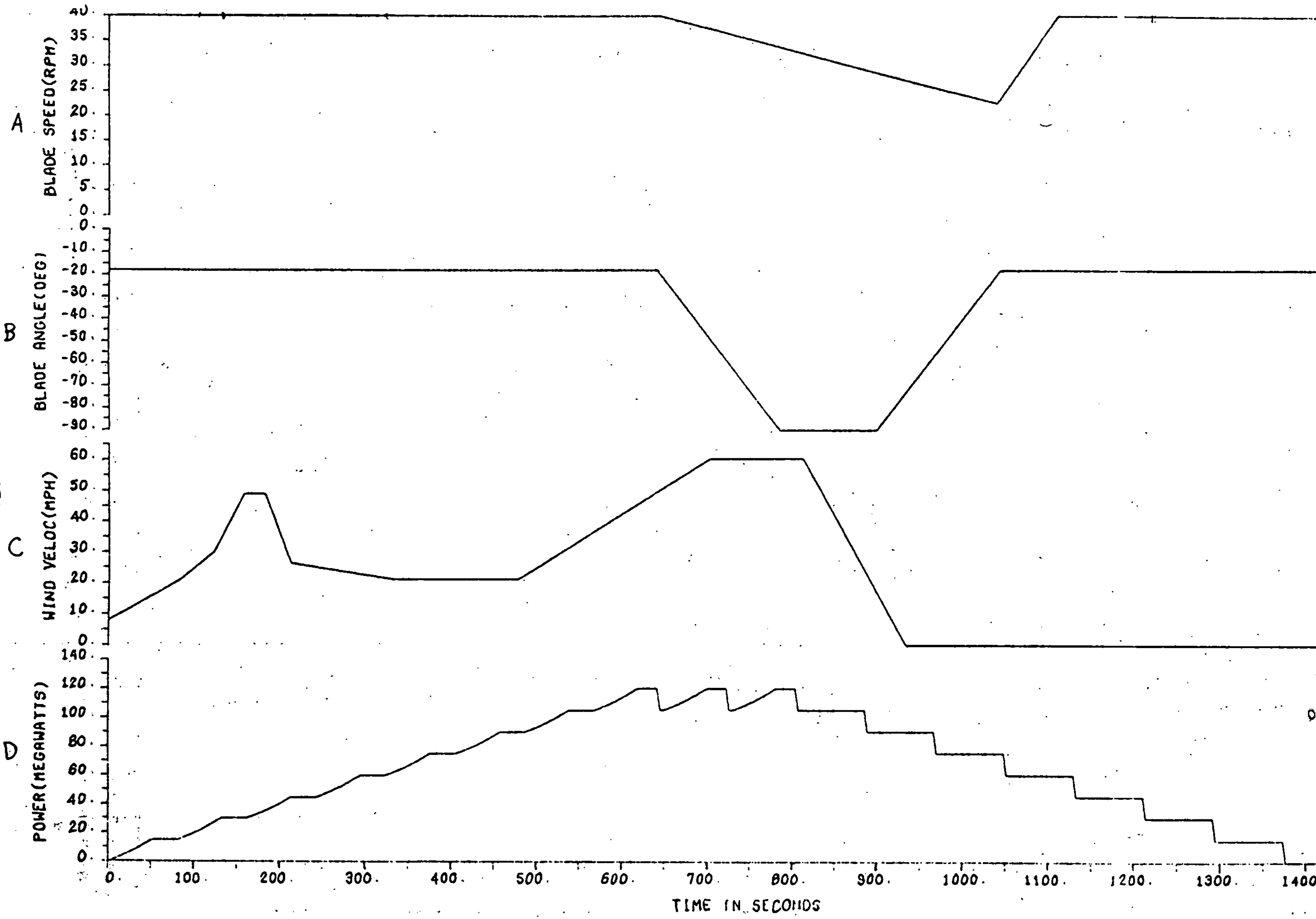


Figure 27 Simulation of the Midwestern Farm for a Thunderstorm Front

Then a shutdown-startup sequence is initiated for that i^{th} generator in the j^{th} wind farm. The WTGs do not experience a shutdown, as the leading edge outflow passes, because the excessive wind speed is not sustained long enough for the average wind speed $\hat{V}_{ij}(kT)$ to exceed 64 km/hr.

The effect of the shutdown-startup sequence on blade rotational speed and blade pitch angle for a WTG in the first echelon is shown in Figures 26A and 26B and 27A and 27B for the coastal and midwestern wind farm configurations, respectively. Note that the rotor blade pitch angle is slewed to the feather position (-90°) at a rate of 30°/min and when the angle has changed 2° all power is lost on the generator. The shutdown sequence thus causes a very rapid loss of generation. Thus the shutdown in each echelon in both the coastal and midwestern farms is observed as sudden drops of all generation in that echelon when the trailing edge inflow passes over that echelon. The rotational speed of the blade also decreases from 40 rpm at a rate of $\frac{2}{45}$ rpm/sec simultaneously as the blade pitch angle is slewed to and held in the feathered position. The trailing edge inflow passes before the blades stop turning and thus the average wind speed $V_{ij}(kT)$ on the i^{th} generator in the j^{th} farm drops below 53 km/hr triggering the startup sequence for that generator and all generators in the echelon that experience this same wind speed profile. The blade pitch angle is slewed back toward zero degrees at a rate of 36°/min after the startup sequence is initiated, as shown for a WTG in the first echelon in Figure 26B and 27B for the coastal and midwestern wind farm configurations, respectively. The rotational speed of the blade does not begin to increase back toward 40 rpm until the rotor angle reaches -17.5° when the blade is capable of capturing enough wind to accelerate the blade speed. The blade then accelerates at 5 rmp/min until the rotational speed reached 40 rpm, as shown in Figure 26A and 27A, for a WTG in the first echelon of the coastal and midwestern farm configuration, respectively.

The power variation out of the coastal wind farm shown in Figure 26D, shows two 75 megawatt ramps each 50 seconds long which are the increases in generation due to the leading edge outflow passing over the two echelons. The two very sharp power decreases are due to the shutdown of WTGs on both echelons caused by sustained wind speed beyond cutoff. The time interval between the successive increases or decreases on the two echelons is 240 seconds.

The power variation on the midwestern farm is shown in Figure 27D. The succession of 15 MW increases are due to the leading edge outflow passing over each echelon. The period of fairly constant total wind power generation is due to the cancellation of the increases in generation on the last three echelon due to the passing of the leading edge outflow by the shutdowns on the first three echelon due to the passing of the trailing edge inflow. The total power then decreases to zero as the shutdown of the remaining seven echelons is caused by the excessive speeds in the trailing edge inflow.

An analysis will not be performed to determine an expression for

(1) the time interval T_M for a 1.5 MW WTG to change from zero to maximum generation for a worst case thunderstorm front

(2) the time interval T_e between either (a) the initiation of generation increases on adjacent echelons due to the leading edge outflow or (b) the shutdown of WTG's in adjacent echelons due to the passing of the trailing edge outflow

This analysis is applicable for any wind farm configuration with WTG's arranged in straight lines and thunderstorm fronts with constant front velocity. The analysis is performed to better understand the power variations out of any wind farm configuration and its impact on response requirements on governor frequency regulation and automatic generation control to handle wind power variations.

The time in seconds for a particular WTG to change its generation from zero to 1.5 MW for a thunderstorm front is

$$T_M = 3600\ D/Vo \quad \text{sec}$$

where Vo is the velocity of the front and D is the distance from the very leading edge of the front to the point internal to the front at which wind speed first reaches the wind speed level (26 km/hr) just sufficient for maximum generation (1.5 MW). Thus, a thunderstorm front with a minimum valve of T_M or D would require a higher response rate for the governor frequency regulation and AGC regulation controls to handle this change in wind power generation without excessive or sustained change in frequency or area control error.

The time interval T_e between initiation of generation changes on two adjacent echelons is

$$T_e = \frac{3600\ d}{Vo} \quad \text{sec}$$

where d is the distance between echelons in miles. The distance d must be greater than D for the response of two adjacent echelons due to passage of the leading edge outflow not to overlap. The shorter T_e and d, the higher the response rate capability of the power system required to handle this generation change without excessive or sustained frequency or area control error changes.

Two other parameters that increase power system response requirements are

N_e the number of WTGs in each echelon

N_f the number of WTGs in any area 25 mi long (the maximum width of the thunderstorm front and 1/6 V_o long [the distance the thunderstorm can move in the time frame of AGC action to meet spinning reserve requirements]

These two numbers are proportional to the penetration level of an echelon ρ_e and a farm ρ_f. These levels are constrained in the next section to avoid excessive and sustained changes in frequency or area control error due to wind power variation exceeding response rate capabilities of governor frequency regulation and automatic generation control. It should be noted that the analysis in this section did depend on farms composed of MOD-OA wind turbine generators but rated at 1.5 MW. The analysis and simulation developed here could easily be applied to any other model wind turbine and wind farm siting configurations.

Section 3: ANALYSIS OF ECHELON AND FARM PENETRATION CONSTRAINTS

Constraints on penetration of any echelon (ρ_e) spacing between any pair of adjacent echelons (d), and the penetration of a farm, which consists of all WTG clusters affected by a thunderstorm front in the time frame of concern are now developed. These constraints are developed ignoring the effects of simultaneous load change which is considered in the next section. These constraints are based on the average response rate capability curve [Ewart 13] for a typical power system, which is shown in Figure 28 and 29. This curve gives the average response rate in percent of system capacity as a function of the interval in minutes over which the average is computed. The average wind power variation rate for a coastal wind farm with 6% penetration during the initial 6 minutes when wind generation is increasing is also plotted in Figure 29. This average wind power variation rate is also given as a function of the interval over which the average is computed. If this wind power variation rate curve exceeds the power system response rate capability curve at some point, either the governor frequency regulation or automatic generation control is not fast enough to respond to the wind power generation increase. The control whose response capability is exceeded, depends on whether the point at which the response rate capability is exceeded lies in the time frame of frequency regulation (< .3 min) or automatic generation control (> .3 min). For a ρ_f = 6% coastal farm penetration or an equivalent ρ_e = 3% echelon penetration, the average wind power varia-

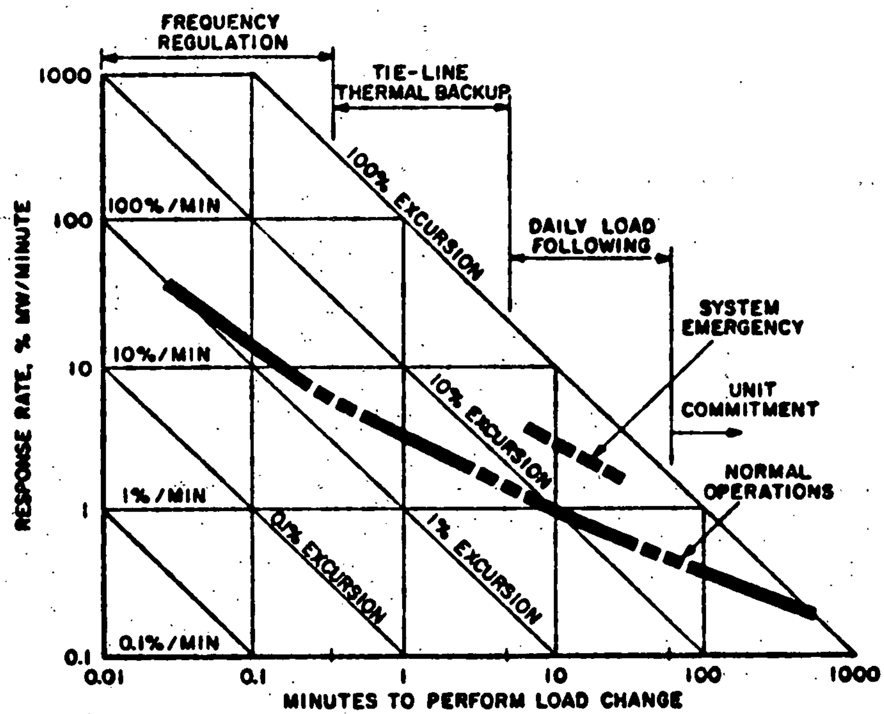


Figure 28 Power System Response Rate Capability

(from ref. 13)

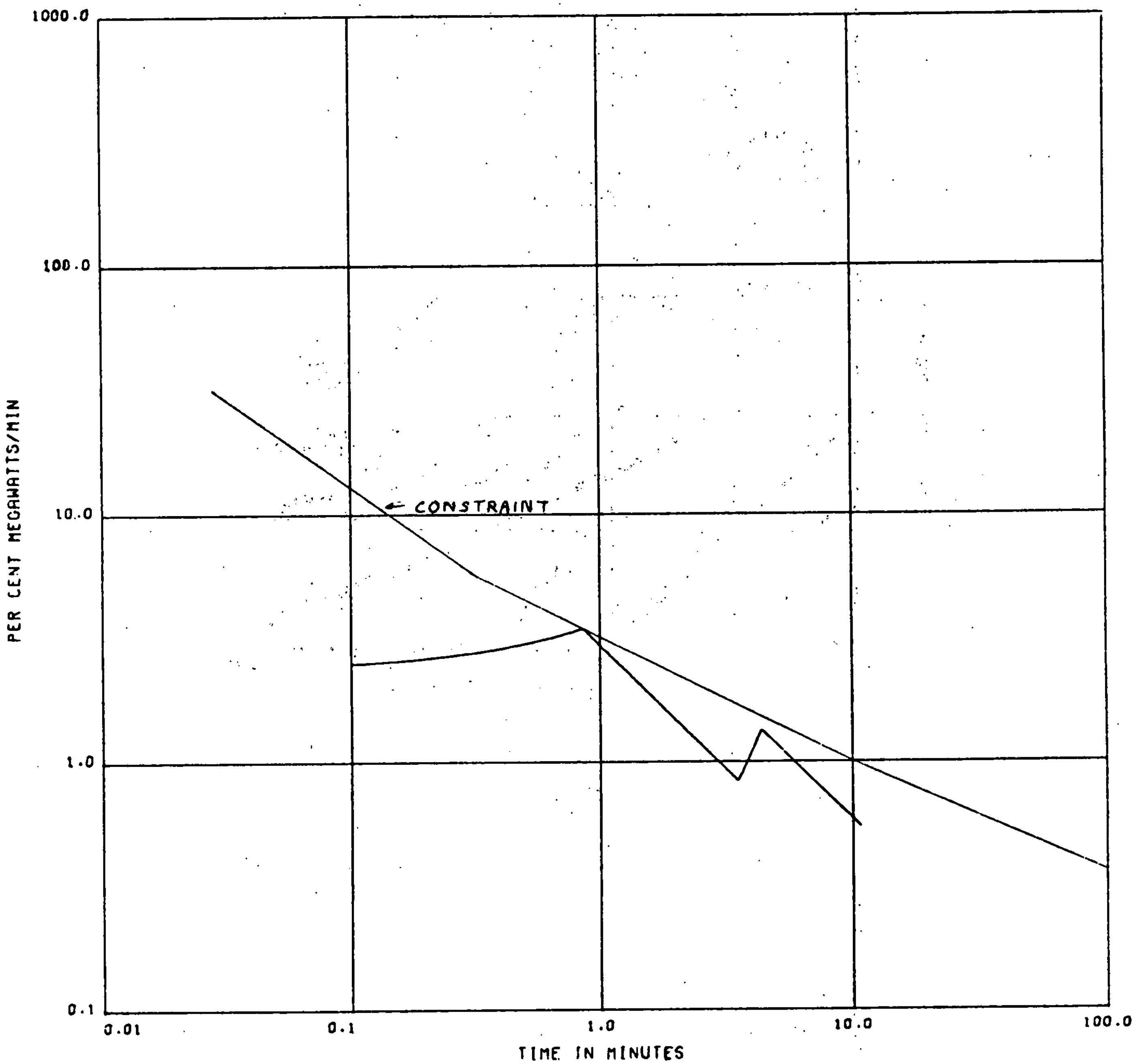


Figure 29 Coastal Farm Power Variation Rate during Passage of Leading Edge Outflow of the Storm Front

tion rate just equals the response rate capability of the typical power system at T = 50 seconds, which is the time T_m that it takes the WTGs in the first echelon to just reach maximum capacity ρ_e, expressed as a percentage of system capacity. Thus, the maximum echelon penetration possible without exceeding AGC regulation response rate capacity is 3% for a thunderstorm front with T_m = 50 seconds.

The power variation rate out of a WTG echelon would increase if the rate of change of wind speed in the leading edge outflow were to increase due to decrease in D or increase in Vo which both decrease the interval T_m over which the increase occurs. However, the power systems response rate capability also increases as the interval (T_m) decreases and in a manner so that the 3% maximum echelon penetration at T_m = 50 seconds would decrease to 2% for a thunderstorm gust front with T_m = 30 seconds. The values of T_m or D are not well known parameters for thunderstorm fronts and thus the fact that penetration remains in a range between 2% and 3% for variation in T_m is important.

The minimum system capacity required to respond to a 50 WTG echelon of 1.5 MW generators given a maximum echelon penetration level of 2%, is 3750 MW. This upper limit on echelon penetration and lower limit on system capacity for a worst case WTG echelon is of course developed assuming there are no other changes in load or generation during this interval and thus that the system frequency regulation is completely devoted to adjusting for this worst case wind power variation for this echelon during this interval. Thus, a maximum echelon somewhat lower than 2-3% and minimum system capacity for a worst case echelon somewhat greater than 3750 MW would be advisable.

The increase of generation on the second echelon 2 miles back of the first echelon, starts at T_m = 240 seconds after the front first causes power variation on the first echelon, is seen on the wind power variation rate curve in Figure 29.

Note that it does not cause the wind power variation curve to exceed the power system response rate capability curve but does cause additional stress on automatic generation control. If the spacing between the two echelon were reduced from d = 2.0 miles to 0.5 miles, the average wind power variation rate curve will remain essentially constant at 3%/min out to approximately 120 seconds for the 3% echelon peneration level regardless of the value of T_m chosen. The wind response rate curve will then exceed the power system response rate curve and the 3% penetration per echelon would have to be reduced to approximately 2% per echelon.

The above analysis of the maximum echelon penetration when the responses of adjacent echelons to the leading edge outflow do not overlap ($T_e > T_m$) and when the responses of adjacent echelons to the leading edge outflow do overlap ($T_e < T_m$) will now be generalized to apply to wind farm configurations where WTGs are not arranged in straight lines. An echelon for the sake of this penetration constraint will now be defined as all WTGs sited in any strip 25 miles wide (the maximum width of a thunderstorm front) and D miles long since all WTGs in this space will respond simultaneously to the leading edge outflow at any instant. If (1) the change in power for a change in wind speed $\frac{\partial P}{\partial Vw}$ is assumed constant for the WTG (2) the rate of change of wind speed with time $\frac{\partial Vw}{\partial t}$ on the leading edge outflow of the front is assumed constant, and (3) the number of WTGs in the 25 strip per distance D $\left(\frac{\partial N}{\partial D}\right)$ is assumed constant; then the rate of change of power out of the echelon defined as a 25 mile wide strip D mile long is

$$\frac{\partial\ P_{echelon}}{\partial t} = \left[\frac{\partial P_{WTG}}{\partial V_W}\ \ \frac{\partial Vw}{\partial t}\right] \left[\frac{\partial N}{\partial D}\qquad D\right]$$

and clearly depends on D. Although the three assumptions are only approximated in general, the conclusion that an echelon's power variation rate depends on D is clear. The distance D for the thunderstorm front shown in Figure 26C is

$$D = 0.416 \text{ miles}$$

The final constraint on the wind farm is the penetration level of the farm itself where a wind farm is defined for this discussion and generalized later as all WTG clusters that are affected by a thunderstorm in the time frame of AGC response to meet spinning reserve requirements. Thus for a thunderstorm front with V_o front velocity and maximum width of 25 miles, the farm is all WTG clusters in an area 25 miles wide and V_o /6 miles long in the direction of the movement of the front. It can be seen from the typical power system rate curve, in Figure 28 that the maximum excursion handled in 10 minutes is ten percent on a typical system. This is the spinning reserve or the generation that the AGC is able to replace in ten minutes. This spinning reserve is typically the size of the largest generator in the system. The size of the farm, composed of all WTG clusters in a 25 mi by 1/6 V_o mile strip, should be less than the spinning reserve margin (5-10%) or less than the largest generator on this system.

The farm defined for this analysis is all WTG clusters in a 25 mi wide, 5 mi long area for a thunderstorm front with front velocity of V_o = 30 mph. This definition is artificial in the respect that many continuous areas, which contain WTG clusters, could be much longer than 5 mi and that this limit was only placed to determine a constraint on the penetration of WTG clusters that could affect AGC in the time frame of spinning reserve requirements. The above penetration constraint should also be applied to a general farm defined as all WTGs in an area 25 mile wide and the depth of the continuous area containing WTG clusters in the direction of motion of the front. The extension of this farm penetration constraint to the general farm on the logic behind the spinning reserve will now be explained based on requirements. These are stated as follows:

(1) it should be possible to replace the capacity of

the largest generator in ten minutes

(2) it should be possible to replace half the capacity of the largest generator in the next twenty minutes

The additional spinning reserve which is to be made available in this second interval, is generally intended to cope with a contingency or load change that is quite independent of that taken care of by the spinning reserve required for the initial interval. Thus, allowing a general farm to have a penetration level larger than the spinning reserve for the first interval would allow one storm front to utilize more of the spinning reserve than desired for any single contingency.

The penetration requirements on wind array generation in a utility is based on just one thunderstorm front in one 25 mi strip of area because the probability that two thunderstorm fronts will affect two such farms is like the probability that the largest two generators will be lost simultaneously which is a worse contingency than is used to set spinning reserve requirements. Thus, the affects of multiple thunderstorm fronts occuring simultaneously in different areas or in different 25 mile strips in the same region are neglected.

Echelon and farm penetration level constraints have been derived that should allow the governor frequency regulation - automatic generation control to cope with the rapid power variation from any echelon and the total power generation changes from any general farm with any siting configuration affected by passage of the leading edge outflow storm front. Thus analysis of the power variations from the midwestern farm configuration for passage of the leading edge outflow a thunderstorm front would confirm

(1) a maximum echelon penetration of 3% is possible when (a) the rate of change of wind speed as the leading edge outflow of a thunderstorm passes through is not too fast, which implies

$$T_m = \frac{3600\ D}{V_o} \geq 50 \text{ seconds}$$

d	-	spacing between WTG echelons	2 mi
D	-	distance between leading edge outflow and the point in the front where wind speed reaches Vrated, the lowest velocity where the machine produce rated power.	.416 mi
V_o	-	the velocity of the front	30 mph
$T_m = \frac{3600D}{V_o}$		time required for the WTGs in an echelon to move from cut in to full rated power for passage of a thunderstorm front	50 sec.
ρ_e	-	echelon penetration	
ρ_f	-	farm penetration	

$$\rho_e = \begin{cases} <2\% & \text{if} \quad d < D \quad \text{or} \quad T_m < 50 \\ <3\% & \text{if} \quad d > D \quad \text{or} \quad T_m \geq 50 \end{cases}$$

$\rho_f <$ spinning reserve margin for first ten minute interval

TABLE 11 Summary of parameter values and constraints on farm and echelon penetration levels

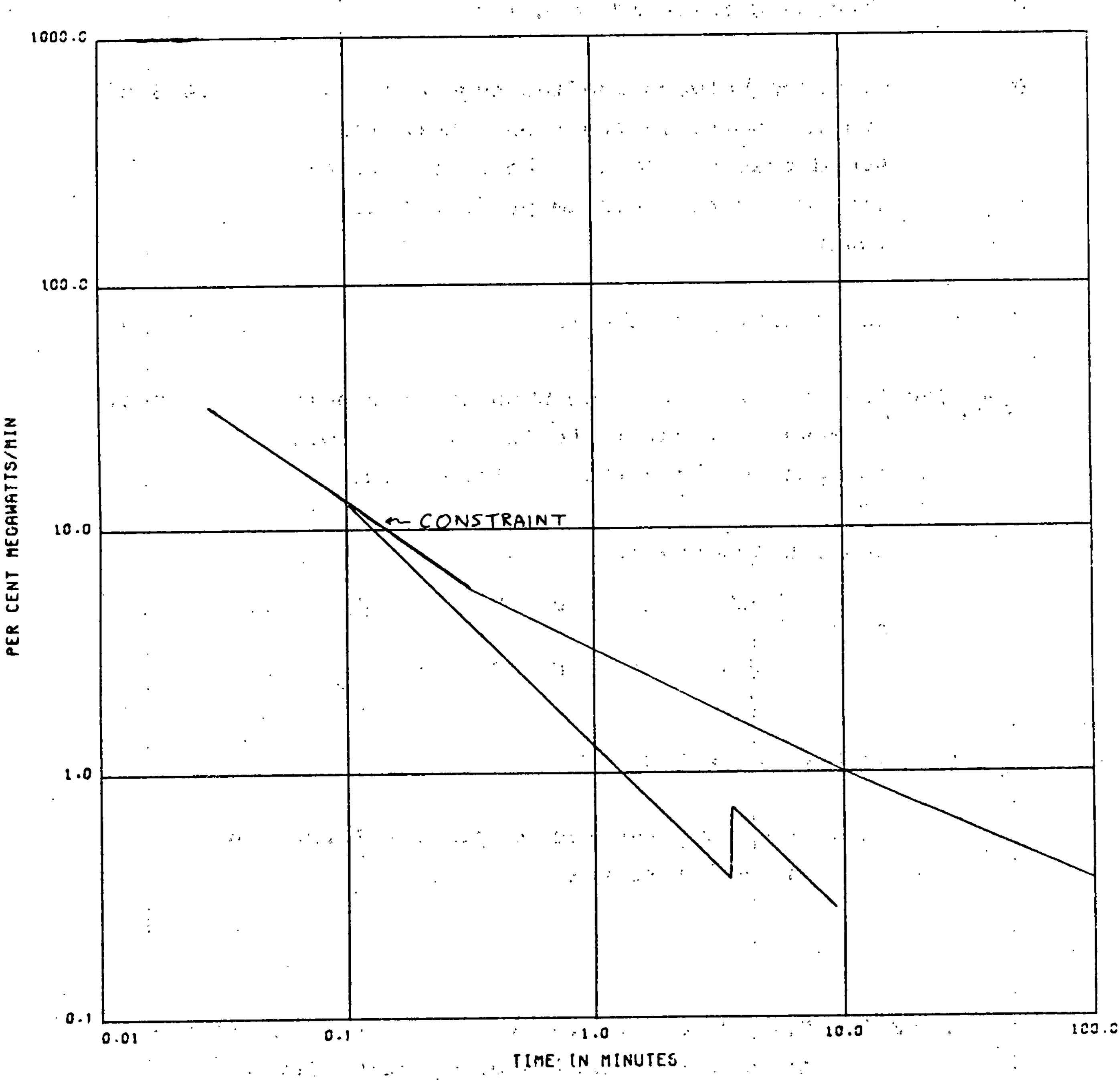


Figure 30 Coastal Farm Power Variation Rate during Passage of the Trailing Edge Inflow of the Storm Front

and (b) the response of adjacent echelons do not overlap

$$d > D$$

where an echelon is defined as all WTG clusters in a strip 25 mi wide and D miles deep.

(2) the maximum echelon penetration level decreases to 2% if (a) the rate of change of wind speed as the leading edge of the thunderstorm passes through is high

$$T_m < 50 \text{ seconds}$$

or (b) if the responses of adjacent echelons to the leading edge outflow overlap

$$d < D$$

(3) the farm penetration level must be less than the spinning reserve margin for the system so that AGC regulation can respond to thunderstorm induced changes in generation from the wind farm.

A farm is defined as all generation in a strip 25 miles wide and the entire length of the continuous area containing WTG clusters affected by the front. These constraints are summarized in Table 11.

The echelon penetration constraint would limit the width of an array of wind turbine generators if the penetration of the WECS generation in a region Do miles wide and D miles long exceeds the echelon penetration constraint. If the echelon penetration constraint for any such region were not exceeded, the width of the WECS array could be arbitrarily large since a thunderstorm can only affect a strip Do miles wide and the echelon penetration in the strip does not exceed the echelon penetration constraint. The farm penetration constraint will not constrain the width of a WECS array. The farm penetration constraint does limit the total number of WTGs affected by a single thunderstorm, i.e., those in any strip Do miles wide and the entire length of motion of the thunderstorm front. This farm penetration constraint limits the loss of WECS generation due to a thunderstorm to be less than that of the spinning reserve requirement on AGC, which is normally about the size of the largest generator in that system.

The wind power variation rate curve for the shutdowns due to passage of the trailing edge inflow on a 2.57% coastal farm is not plotted along with power system response rate capability in Figure 30. The shutdown is like a generator contingency and thus frequency regulation should not be expected to cope with this change. Thus the shutdowns of an echelon may cause power variations that exceed power system response rate capability even if the echelon penetration constraint is observed. However, the power variation from shutdowns will not exceed spinning reserve margins if the farm penetration constraint is observed. The shutdowns are like loss of generation contingencies and thus the echelon penetration is not constrained so that frequency regulation can cope with the change but farm penetration is constrained so that AGC regulation can meet the change and meet NAPSIC performance specifications.

The results would suggest that if echelon and farm penetration constraints are observed, the power system should operate satisfactorily for thunderstorm induced WECS generation changes. The results in the next section will prove that

(1) an AGC saturation problem will exist whenever simultaneous load and WECS generation change exceed spinning reserve margins. This saturation problem can happen when farm penetration itself is far below spinning reserve margins during morning pickup or evening dropoff for simultaneous passage of a thunderstorm through a wind farm. This AGC saturation will cause violation of NAPSIC performance requirements on AGC.

(2) a cycling problem on nuclear units can occur if echelon generation capacities are large enough to cause frequency deviations that are larger than governor deadband. This problem can occur even when echelon penetration levels are small compared to echelon penetration constraints and will not cause large sustained frequency deviations.

The analysis of farm and echelon penetration constraints does provide useful information on constraining wind farm generation variation so that large sustained frequency deviations do not occur for power variation on an echelon and so that large sustained area control error deviations do not occur for power variation from a farm. The fact that operating problems still exist is a concern and must be dealt with by modifying the AGC, economic dispatch, governor frequency regulation, and possibly the unit commitment and generation mix.

The maximum system capacity, where the theoretical worst case farm will have power variations that exceed the system's response rate capability, is now derived. This analysis will indicate the approximate size of systems that will definitely have operating problems from a theoretical a worst case echelon or a theoretical worst case farm.

A system having a capacity of under 3750 MW will have operating problems for a 50 WTG echelon spaced 0.5 miles apart when a 2% echelon penetration constraint is known to give a power variation rate from this echelon for the thunderstorm front equal to the power system response rate capability at a particular point. A system having a capacity of under 6075 MW with a 10% spinning reserve margin will have operating problems for a theoretical worst case wind farm of 405 WTGs spaced 0.57 mi apart in a 25 mi by 5 mi strip. If a 5% penetration farm was the maximum that could be replaced by AGC in the time frame of spinning reserve requirements, a system of under 12,150 MW would have operating problems in responding to power variations from this theoretical worst case farm.

Thus, wind power variations from a worst case echelon or farm are guaranteed to cause operating problems on a small to moderate sized utility. The more severe operating problem between worst case echelon power variation or worst case farm power variation is that from the worst case farm since a 6000 MW - 12,000 MW system would easily respond to the worst case echelon variation rate but would just be able to respond to the worst case farm power variation rate.

This analysis would indicate a 20,000 MW capacity system could easily respond to worst case echelon and farm power variations and thus should be able to respond to any farm that met echelon and farm penetration constraints. However, in using the analysis for the maximum system capacity values that assure operating problems one must consider

(1) that any actual wind farm will not have a worst case echelon or farm configuration and will produce power variations with much smaller average rates of change

(2) the power system is expected to respond to load variation simultaneously with these wind power variations and thus systems larger than these maximum capacities would experience operating problems given simultaneous thunderstorm induced WECS generation and load changes.

The next section will indicate the operating problems for load and thunderstorm induced generation changes coastal and midwestern farms with 3.75% farm penetration levels. These results will show operating problems exist for simultaneous load and thunderstorm-induced WECS generation changes when farm penetration levels are significantly below the upper limits determined in this section.

Section 4: EFFECTS OF WIND POWER AND LOAD VARIATION ON AGC REGULATION AND GOVERNOR FREQUENCY REGULATION

The purpose of this section is to investigate the operating problems when

(1) farm penetration
(2) echelon penetration
(3) load variation rate expressed as a percentage of capacity

are high. Specifically, the objectives are

(1) to show that the AGC regulation becomes saturated and thus cannot meet NAPSIC performance requirements whenever the total power generation change in an interval due to simultaneous load and storm induced WECS generation changes exceed the system spinning reserve requirement for that interval. This operating problem can be more frequent than one due to typical loss of generation contingencies since the problem appears when storm fronts pass thru arrays during morning pickup or evening dropoff.
(2) to show that increasing spinning reserve margins, which are set based on a study of system reliability that includes WECS generation, could alleviate this AGC regulation problem. This is the major result of this section because it indicates a solution to the major operating problem when WECS penetration is high. The setting of the spinning reserve margins must of course be done through a system reliability study but this work indicates an increase in typical spinning reserve levels might be justified when WECS penetration is significant.
(3) to show that changes in generation mix to include higher percentages of fast responding generation (hydro, gas turbines) can have a significant effect on AGC regulation response to WECS generation changes when regulation is not in saturation.
(4) to show that cycling of nuclear units on governor frequency regulation can be severe when a storm front passes through a farm where several echelons have 50 WTGs, which is the maximum number that can

be affected in any echelon by a single thunderstorm front. This problem would not appear if the generation capacity of each echelon were not large enough to cause frequency oscillations that exceed governor deadband of the generators in the system.

The results in the previous section gave theoretical upper limits for farm and echelon penetration when load variation was assumed zero. This study shows (1) that operating problems can exist when farm and echelon penetration levels are lower than these theoretical maxima and (2) possible methods of reducing or eliminating these operating problems. This study is carried out through use of the PJM-derived simulation to study several cases that are selected to determine whether operating problems exist and how they may be relieved. Area control error, tie line power, frequency, and the generation levels of the units on base load, economic dispatch and regulation are plotted to document the results.

The 150 MW coastal and midwestern farms were considered to be too small to have much effect on the 20,000 MW capacity PJM system from results of the previous section. Thus to obtain significant farm penetration of 3.75%, 750 MW coastal and midwestern farms were used by multiplying the outputs of the 150 MW farms by five. Although the operating problems for a 3.75% coastal farm and ½% per minute load variation rate should be similar on a system of any capacity; the frequency, tie line power, and area should be five times that of a 3.75% 150 MW farm with ½% per minute load variation on a 4000 MW capacity system. Thus, the PJM system model for the evening dropoff was downsized to 4000 MW by cutting internal system inertia (HINT), frequency bias (B), generating unit levels ($PG_j(0)$) and capacities (CAP_j), generating cost curve coefficients ($1/c_j$) and the spinning reserve (ACEMAX) by five although the percentage spinning reserve was kept at 5%. The morning pickup #1 unit commitment for the 20,000 MW PJM, and the evening dropoff unit commitment for the 4000 MW system were both run with wind power variations from 3.75% penetration coastal farms and a ½% per minute load variations. These runs show and confirm

(1) that the AGC regulation with a 5% spinning reserve becomes saturated and thus does not meet NAPSIC performance requirements when a thunderstorm induced 3.75% change in WECS generation and ½% per minute load variation occur simultaneously to require a total 7.5% change in generation in a ten minute interval. The violation is not a function of system size but dependent on whether the total percentage change in generation caused by load and WECS generation changes in an interval exceed the system spinning reserve margins for that interval.

(2) that saturation of AGC regulation could occur for both evening dropoff or morning pickup since the total load and WECS generation changes could exceed typical spinning reserve requirements set for the case where WECS generation changes are not present.

(3) that peak frequency, area control error, and tie line power deviations depend on the capacity of the farm and not on the penetration level. The existence and duration of the saturation problems depended on how much the sum of the farm penetration and percentage load variation in a ten minute interval exceeded spinning reserve margin expressed as a percentage of system capacity.

A brief study is then undertaken to determine possible solutions for this AGC saturation problem. The regulation participation of a hydro unit was approximately doubled in an effort to increase the percentage of the AGC regulation undertaken by fast responding units. The improvement was only slight because the area requirement was saturated so that faster responding generation were not required to increase generation more than the slower units it replaced. In a second run, the saturation level ACEMAX on the area requirement was increased from 200 to 280 MW thus increasing spinning reserve from 5% to about 7%. The saturation of the area requirement for such a long period after the shutdown of the second echelon was eliminated and the saturation of the AGC regulation was avoided although the area control error did not cross zero due to the large prolonged load increase that continued long after the changes in WECS generation was completed.

An increase in spinning reserve can only be justified through a thorough system reliability study. The results that indicate this saturation problem can be eliminated by an increase in spinning reserve are very significant because they provide an expanded understanding of the spinning reserve requirement when WECS penetration is significant.

A second morning pickup unit commitment on the 20,000 MW system with the 3.75% 750 MW coastal farm and ½% per minute load variation is run to show that significant changes in generation mix can have a significant effect on the response rate of the AGC regulation when the AGC regulation is not saturated as it was when the percentage of hydro on regulation was doubled in an effort to solve the regulation saturation problem.

A summer peak unit commitment on the 20,000 MW system is run with the 750 MW 3.75% coastal farm and no load variation to confirm that a 3.75% coastal farm will not alone cause violation of NAPSIC performance requirement on AGC regulation.

The summer peak unit commitment on the 20,000 MW system was rerun with the 3.75% 750 MW midwestern farm to show

(1) that placing the WTGs in several echelons rather than just two reduces the magnitude of peak frequency and area control error deviations

(2) cycling of units on governor frequency regulation can be severe when a thunderstorm front passes through a farm where several echelons have 50 WTGs, which is the maximum number that can be affected in any echelon by a thunderstorm front as discussed in section

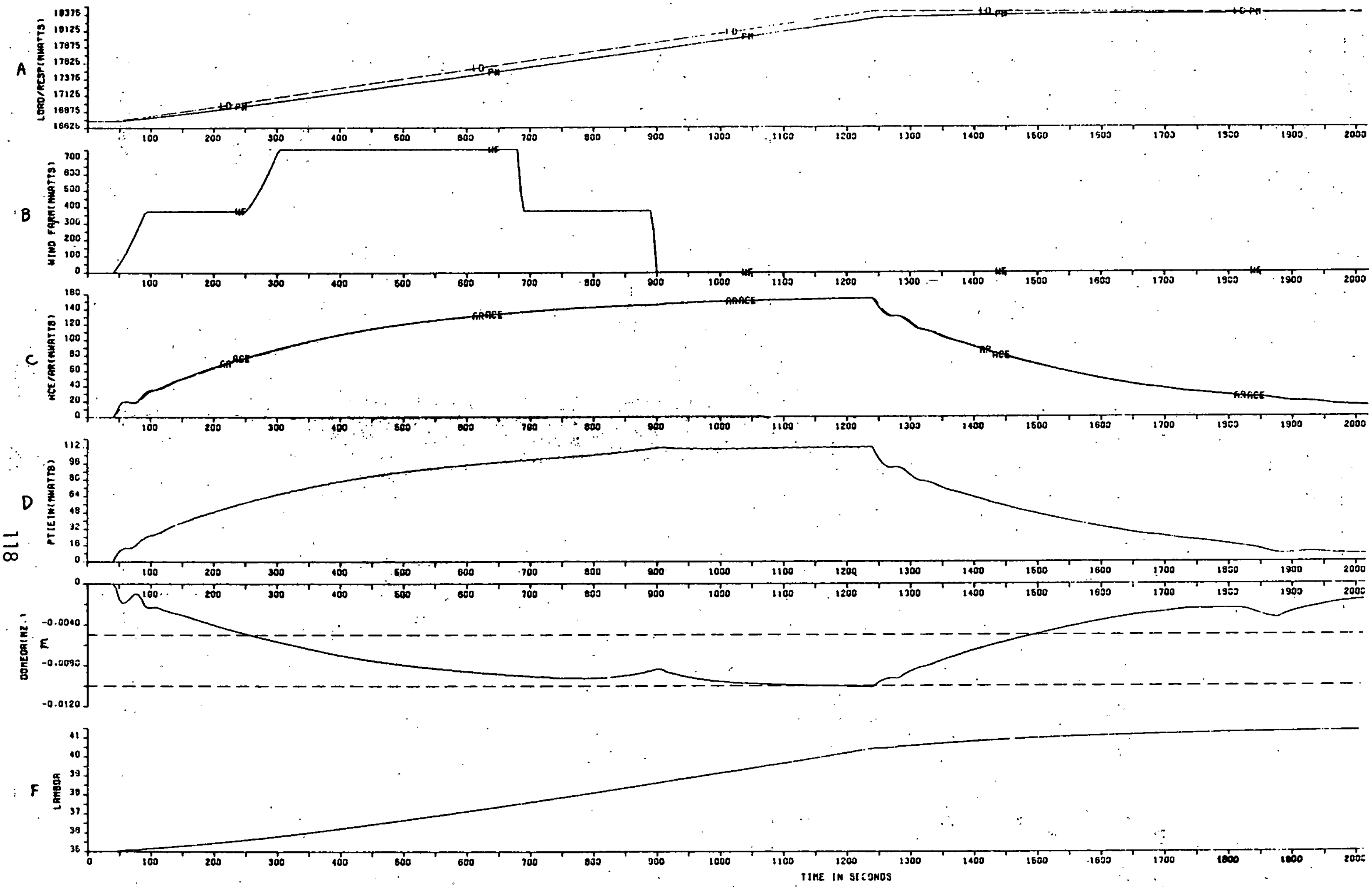


Figure 31 Morning Pickup #1 with Load Variation only

1. The cycling problem will be shown to occur whenever echelon generation capacity is large enough to cause frequency oscillations that are larger than governor deadband.

A brief discussion of WTG siting in a echelon that will alleviate the cycling problem and a constraint on farm penetration that will avoid AGC regulation saturation spinning reserve requirements is then discussed. Both of these constraints would reduce the possible energy from a wind farm and thus such constraints would only be implemented after assessing their economic impact as well as other methods of alleviating the cycling and AGC regulation response problems.

Before actual simulation runs with wind power variations are presented, a base case morning pickup (with the half percent per minute load increase for twenty minutes duration) simulation run is presented to document that the power system simulation is working satisfactorily. This half percent per minute load variation is as large a sustained load variation change that a typical power system will experience and thus is a good test to determine if the simulation generates signals with the proper magnitudes and shapes.

The load variation (LD) shown in Figure 31A, has a 20 minute ramp increase at a slope of ½% per minute. At t=1200s., the load becomes constant and remains so until the end of the simulation (t=2400s.). The frequency, shown in Figure 31D decreases as the load increases until at t = 1200s. the frequency has dropped 0.01 hz. The magnitude of this drop is large but is quite reasonable for the load variation experienced. The deviation then decays toward zero and nearly reaches zero at t=2400s. The area control error (ACE) and tie line power signals, shown in Figure 31B and 31C respectively, increase to 160 MW and 112 MW respectively at t=1200s. and then decay to nearly zero as t=2400s. The peak magnitude of area control error is slightly larger then NAPSIC requirements for a 20,000 MW system (135 MW) but is still satisfactory considering the very high and sustained rate of load variation experienced.

The simulation was not run long enough to indicate the "payback" of energy that would occur due to the integrator in the compensator for the economic dispatch signal LAMDA.

The change in generating level of the hydro unit on regulation is shown in Figure 32B and the level follows the area requirement (AR) signal in Figure 31C perfectly. The hydro unit has a peak change in generation of 52 MW at t=1200s. The changes in generation on coal drum (CD) and oil drum (OD) units on regulation and economic dispatch are shown in Figure 32F. The generation levels increase with load until t=1200s and then increase only slightly as load is taken off the hydro and base loaded units which did initially add power to compensate for the load increase. The frequency regulation and AGC regulation components on these units are reduced to zero during this interval but is more than compensated for by larger economic dispatch commands resulting in the increase sum from t=1200 to t=2400.

The changes in generation on coal drum (CD) and oil drum (OD) on economic dispatch shown in Figure 32E was larger than for the units on both regulation and economic dispatch due to the much larger capacity of units on both economic dispatch and regulation than of units on economic dispatch alone. However, it is interesting to note that the relative increase of generation on the second 1200s. interval is larger for the economic dispatch units because there is no decreasing regulation signal on these units over this interval.

The baseloaded units and nuclear units are shown in Figures 32C and 32D respectively. These signals are small and follow the frequency deviation signal rather closely because these changes are due to the governor frequency regulation control.

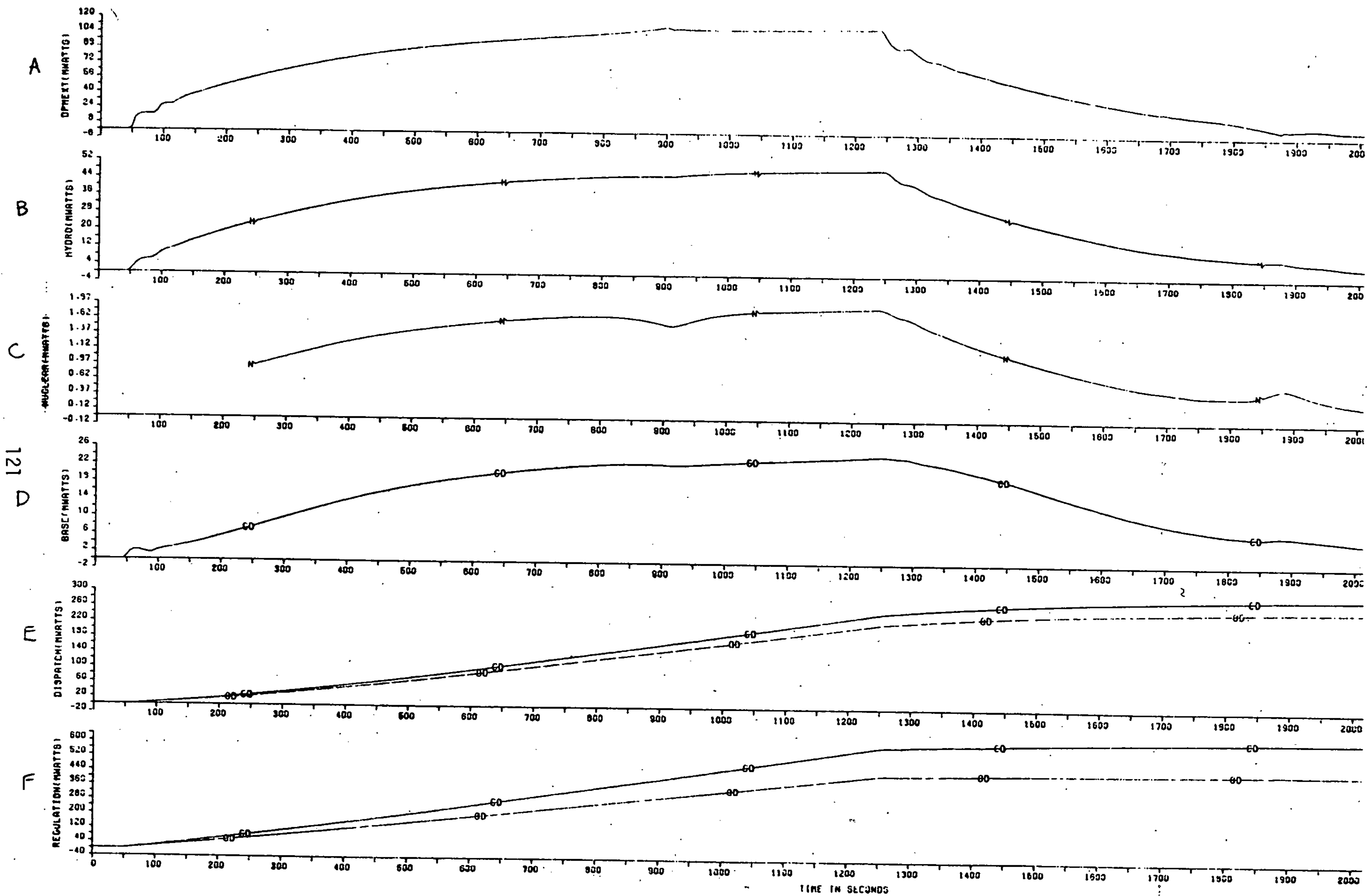


Figure 32 Generator Responses for Morning Pickup #1 without Coastal Farm

Morning Pickup #1 with Coastal Farm

The morning pickup #1 unit commitment with one half percent per minute load variation, as just presented in the base case, is now rerun with a 750 MW 3.75% penetration coastal wind farm. The load (LD) and mechanical power (PM) from all generation including the wind farm, are plotted in Figure 33A. The increases in WECS generation due to the outflow hitting each echelon and even the WTG shutdowns that occur are seen as small compared to the total load variation over the same interval. Moreover, this increase in WECS generation is cancelled by the shutdown just 11 minutes later. The frequency regulation and automatic generation control regulation can handle the wind generation increases in both echelons without excessive or sustained changes in frequency, tie line power, or area control error (ACE), as shown in Figures 33E, 33D, and 33C respectively. The shutdown of the two echelons causes a much larger and sustained errors in frequency, tie line power, and area control error. This occurs partially, because the WECS generation shutdown and load variation both require increased generation and saturate the area requirement signal, and thus the AGC regulation control cannot quickly reduce frequency, tie line power, and area control error. The shutdown of the second echelon causes a larger and more sustained effect than shutdown of the first echelon because when the shutdown of the second echelon occurs the area requirement signal is still saturated due to the shutdown of the first echelon. Therefore, the automatic generation control regulation does not respond at all to this lost generation on the second echelon causing a very large area control error, frequency deviation and tie line power deviation to occur. The governor frequency regulation does respond to the second echelon shutdown but its effect is small. An indication of the severity of the operating problem is that area control error never crosses zero in ten minutes after shutdown of the second echelon violating NAPSIC requirements on AGC regulation

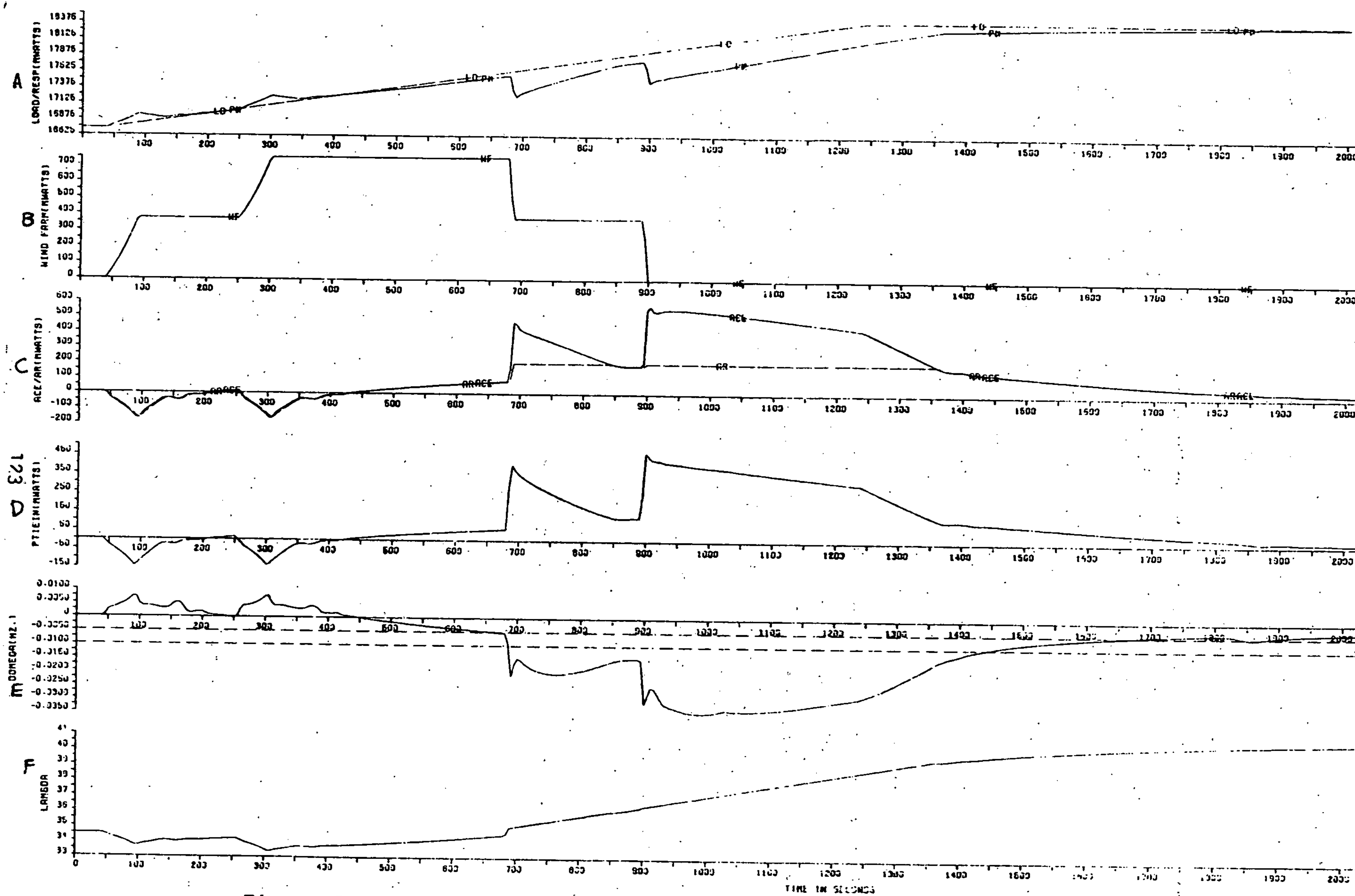


Figure 33 Morning Pickup #1 with Coastal Farm and Load Variation

performance. Moreover, the area requirements (AR) remains in saturation and frequency deviation remains above 0.01 hz for almost 7½ minutes after the second echelon experiences the shutdown, indicating there is no possiblity of performing AGC regulation for this shutdown of the second echelon. Although (1) the absolute size of the wind power variation is not large compared to the load variation and (2) the wind generation increase is cancelled by shutdown in the time interval of the load increase so no additional generation is required over that in the base case, the operating problem that results due to the shutdowns during large load variations is significant. It is due not to the size of the WECS generation changes but rather to the fact AGC regulation could not respond to the large demand in a short interval caused by shutdown of the wind generation and the simultaneous large load increase. The AGC regulation is pushed into saturation, thus it does not recover quickly.

The economic dispatch units (OD, CO) and economic dispatch and regulation units (OD, CD), shown in Figures 34E and 34F respectively, are too slow to show much of an immediate response to wind generation changes. Thus these units show minor fluctuations until t=700 seconds when the first echelon shutdown occurs because in this 700 second interval the wind power generation increase almost cancels the load increase. The rate of generation increase changes suddenly at the shutdown of first echelon for these four units but this rate of generation increase does not change at all for the second echelon shutdown since the area requirement signal is still at or near saturation when this second echelon shutdown occurs (t=900s.). The rate of increase of generation on these four units begins decreasing slightly at t=1350s when load variation has stopped (t=1200s) permitting area requirement to come out of saturation and begin decreasing. The generation level on the economic dispatch and economic dispatch and regulation units is nearly constant at t=2400s.

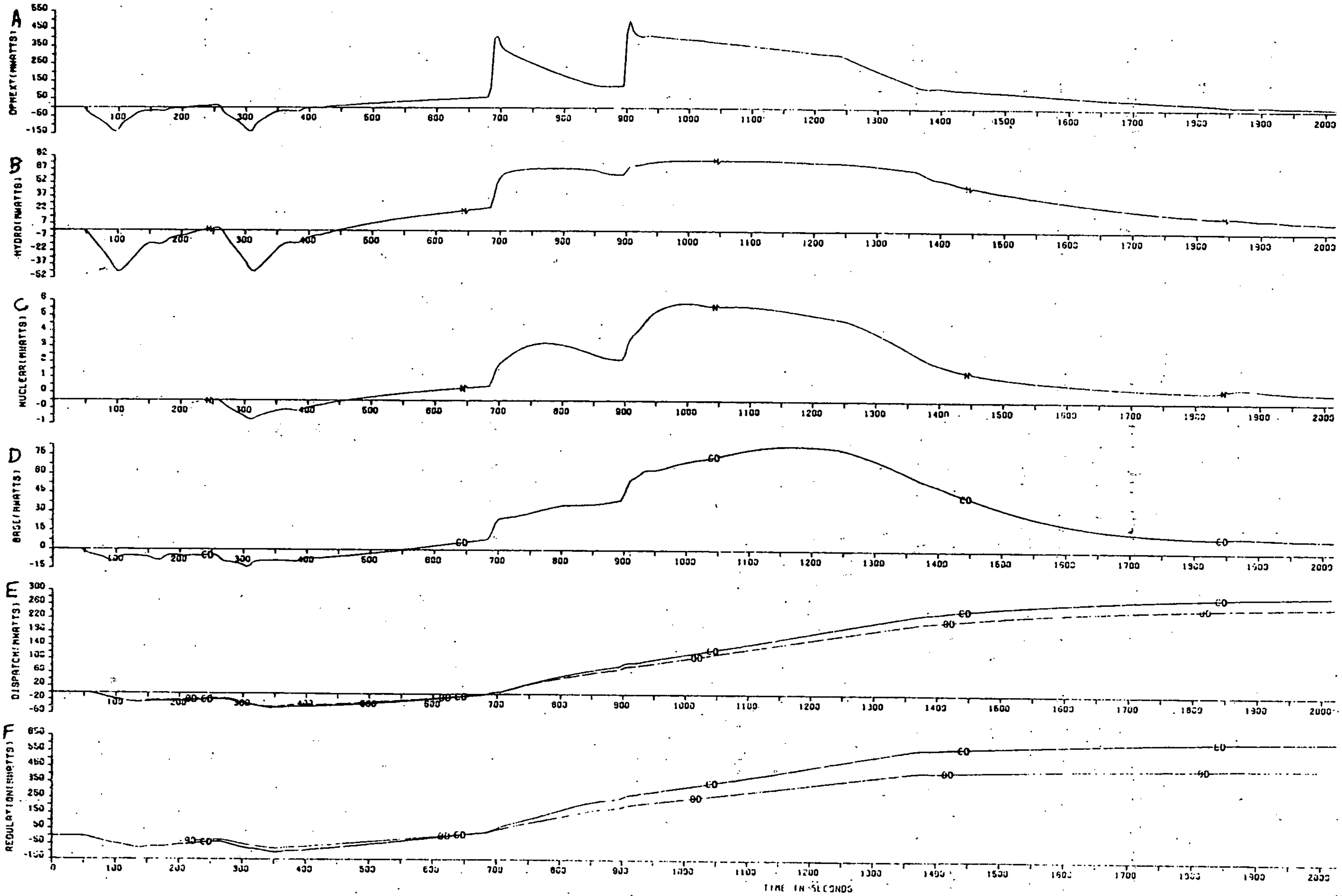


Figure 34 Generator Responses for Morning Pickup #1 with a Coastal Farm

The frequency regulation on the base loaded units and the base loaded nuclear unit, see Figures 34D and 34C, did respond to each wind power generation increase or decrease although the changes in generation were not large until frequency deviation became large when AGC regulation became saturated. The generation level on these units dropped as the frequency deviation began to decay toward zero.

The hydro unit under both governor frequency regulations and AGC regulation controls responded quickly and in a significant manner to compensate for the increases in generation on both echelons and the decrease in generation on the first echelon. However, the hydro unit responded in only a very small way to the shutdown of the second echelon since the area requirement and AGC regulation control are saturated at this point and do not change at the shutdown of this second echelon. The generation change on this hydro unit decreases toward zero as the frequency deviation and area requirement decrease toward zero.

It should be remembered that the magnitude of the frequency, tie line power and area control error signals are five times the size for this 750 MW farm than they would be for a 150 MW farm. However, the operating problems seen in the lack of response will now be shown to be common to any system with a 5% spinning reserve experiencing a ½% per minute load variation and shutdown of a 3.75% penetraion farm by the study of the results for a 150 MW 3.75% coastal farm run on the 4000 MW system during an evening dropoff with a ½% per minute load decrease.

Evening Dropoff with Coastal Farm

An evening dropoff unit commitment for the 4000 MW system with the 3.75% 150 MW coastal farm anc ½% per minute load decrease is now run to show (1) that the maximum magnitude of the frequency, tie line power, and area control error for a 150 MW coastal farm is approximately one fifth of that for the 750 MW farm and is independent of whether that farm appears on the 4000 MW or 20,000 MW internal system and (2) to show that the total percentage generation requirements (due to generation change and ½% load variation) on a 3.75% coastal farm will produce the same operating problems in terms of lack of AGC regulation response for either a 20,000 or 4000 MW system. The major difference between the above morning pickup #1 run and this evening dropoff is that the operating problem occurs for the WECS generation increase and ½% per minute load decrease. This difference causes the stress on AGC regulation to occur immediately when the wind generation increases as observed in Figure 35E, 35D, and 35C for frequency, area control error, and tie line power. The AGC regulation on the evening dropoff run would have remained in saturation for a period as long as that for the morning pickup except that the shutdown of the first echelon brought the area requirement out of saturation as observed in Figure 35D. The results on the evening dropoff and morning pickup cases suggest that the severity of the operating problem for simultaneous WECS generation and load change is dependent on how much the total percentage change in load and WECS generation in a ten minute period exceeds the spinning reserve requirements for that interval. This hypothesis is confirmed by noting that no operating problem existed when a 4% load variation occurred with no WECS generation in the base case and when a 3.75% change in WECS generation occurs without load variation (in the summer peak unit commitment runs to be discussed later) but occurs for the morning pickup #1 and evening dropoff when total percentage change in AGC regulation is 7.5% on systems with 5% spinning reserve. The result in the next subsection will show that increasing spinning reserve to 7% from 5% alleviates the saturation and thus significantly improves AGC regulation performance.

The magnitude of the peak frequency deviation, area control error, and tie line power deviation is shown to be proportional to the size of the farm experiencing the passage of

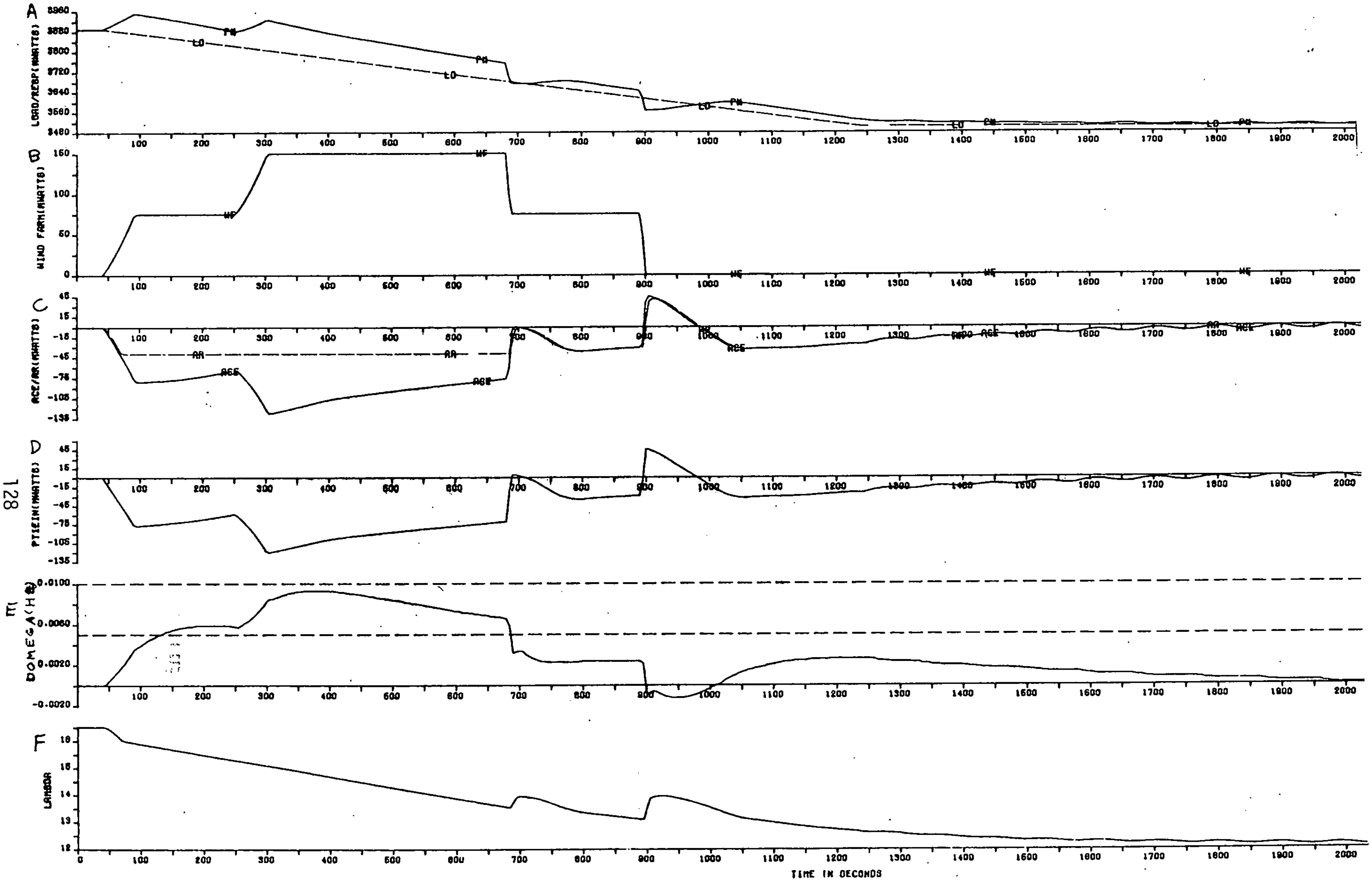


Figure 35 Evening Dropoff with Coastal Farm and Load Variation

the thunderstorm front because the frequency, area control error, and tie line power are nearly zero just before the WECS generation changes that resulted in the peaks for these signals. The peak of the area control error, tie line power and frequency is thus five times larger for the 750 MW coastal farm on the morning pickup than it was on the evening dropoff run. The differences in the size of the internal system had little if any effect on these maxima. This confirms that maxima of frequency, tie line power, and area control error depend on the magnitude of total generation changes required of AGC regulation over a relatively short interval.

Improvement of AGC Regulation Response

A brief study was performed to check a solution that alleviates the saturation of AGC regulation and thus speeds the response of AGC regulation when significant load and WECS generation changes occur simultaneously. The first change made was to double the participation factor of the hydro unit under regulation and thus to reduce the regulation participation factor (α_j) for the oil and coal drum units under both regulation and economic dispatch. Very little effect on the speed of response is observed by comparing the area control error and frequency, shown in Figures 36D and 36C for two sets of AGC regulation participation factors on the morning pickup #1 unit commitment on the 20,000 MW system with the 750 MW farm and the ½% per minute load increase. A second modification was to increase the ACEMAX saturation level from 200 to 280 MW on the area control error increasing the spinning reserve in a ten minute interval from 5% to 7%. The speed of response of the automatic generation control regulation increased significantly almost eliminating the saturation problem of the AGC regulation. This occurs because the interval over which area requirement is saturated and the area control error deviation after the shutdown of the second echelon are significantly reduced.

The purpose of this study was to determine if an operating

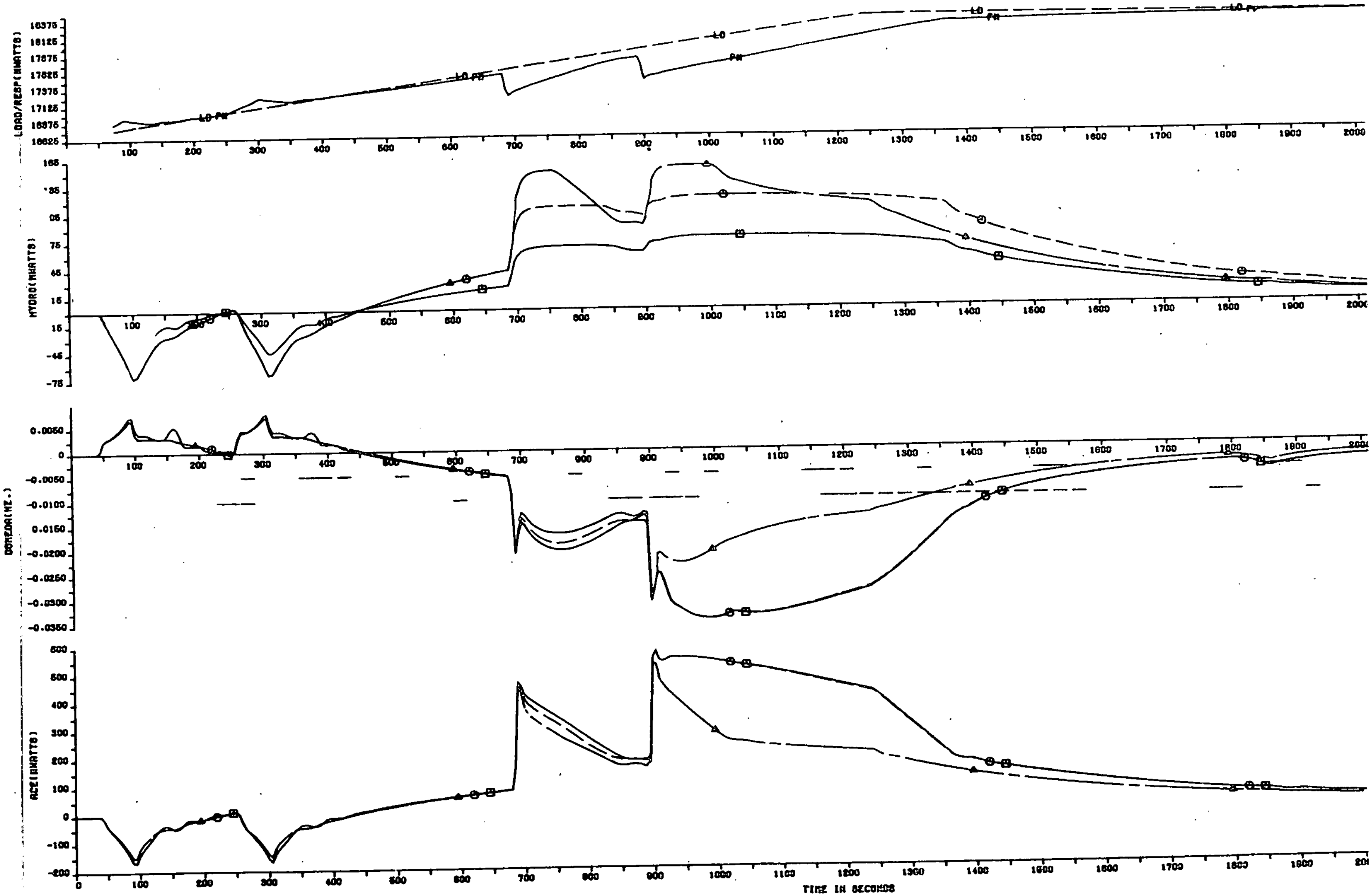


Figure 36 Solution of the AGC Saturation Problem

problem would exist when simultaneous load and thunderstorm induced generation changes occur, and how to solve the problem. One solution is to increase the spinning reserve requirements above those required when no WECS generation changes are present. It is not the purpose of this study to determine if such an increase in spinning reserve should be required since that determination must also be based on a study of system reliability with WECS generation present. However, it should be noted that this AGC regulation saturation operating problem could occur relatively often since large load variation for evening dropoff and morning pickup occur everyday and since the large thunderstorm induced WECS generation changes could occur relatively often compared to other specific typical loss of generation or loss of load contingencies.

A study of system reliability with WECS generation would require knowledge of the probability of WECS generation losses. This probability of WECS generation loss could use the information on the maximum generation lost by a single thunderstorm front presented in section 1, as well as the frequency of thunderstorm fronts.

Morning Pickup #2 and Coastal Farm

A second morning pickup unit commitment was run for the 20,000 MW PJM system with the half percent per minute load variation and the 750 MW 3.75% penetration coastal wind farm. This case was run because the morning pickup #2 unit commitment is significantly different than the morning pickup #1 because no hydro units were available for AGC regulation and supercritical units were used for regulation in place of the faster responding hydro units used in morning pickup #1. This simulation run is intended to show that the generation mix used in a particular operating condition such as morning pickup can have a significant effect on the performance of the automatic generation control and frequency regulation when the area requirement is not saturated as it was in the case where hydro participation factor was increased to as a method of alleviating the saturation problem. The change in AGC reponse for change in generation mix can be observed by noting the 25% larger but similarly shaped area control error and tie line power deviation signals, shown in Figure 37D and 37C, for the morning pickup #2 over that for the morning pickup #1. The lack of fast responding hydro units can also be noted in the significantly slower decay of the area control error after the first echelon and second echelon shutdowns. The frequency deviation shown in Figure 37E, is also approximately 25% larger for morning pickup #2.

The lack of a hydro regulating unit is also seen by observing the small changes on the base hydro unit shown in Figure 38B compared to that for the regulating hydro unit for morning pickup #1. The supercritical unit plotted in Figure 38E should be taking up the hydro unit regulation task but is clearly not fast enough to compensate for the wind power changes.

The nuclear, (CD OD) economic dispatch units, and (OD CD) economic dispatch-regulation units generation curves are similar in shape to those for morning pickup #1.

Summer Peak and Coastal Wind Farm

A summer peak unit commitment on the 20,000 MW with the 3.75 % 750 MW coastal farm and no load variation was run to confirm the results of the previous section that a 3.75% change in WECS generation over a ten minute interval will not cause operating problems as long as the spinning reserve, which is 5% on this PJM system, is larger than the wind farm penetration level. Simultaneous WECS generation and load changes have already been shown to cause operating problem when neither one separately could cause such a problem.

The load power (LD) and mechanical power (PM) out of all machines including wind generation is shown in Figure 39A. The area control error and tie line power, shown in Figures 39D and 39C, indicate an immediate decrease and slow decay

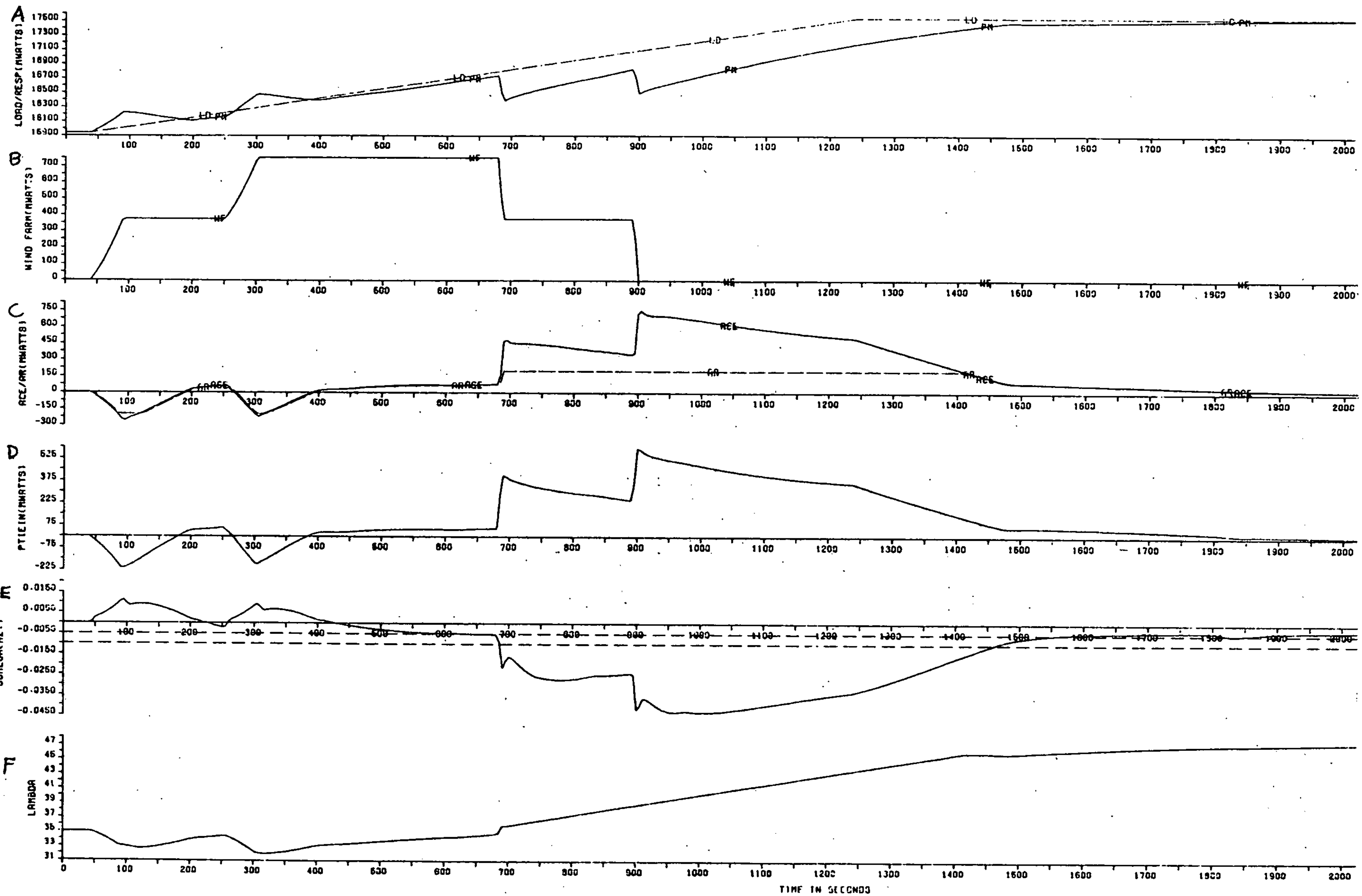


Figure 37 Morning Pickup #2 with Coastal Farm and Load Variation

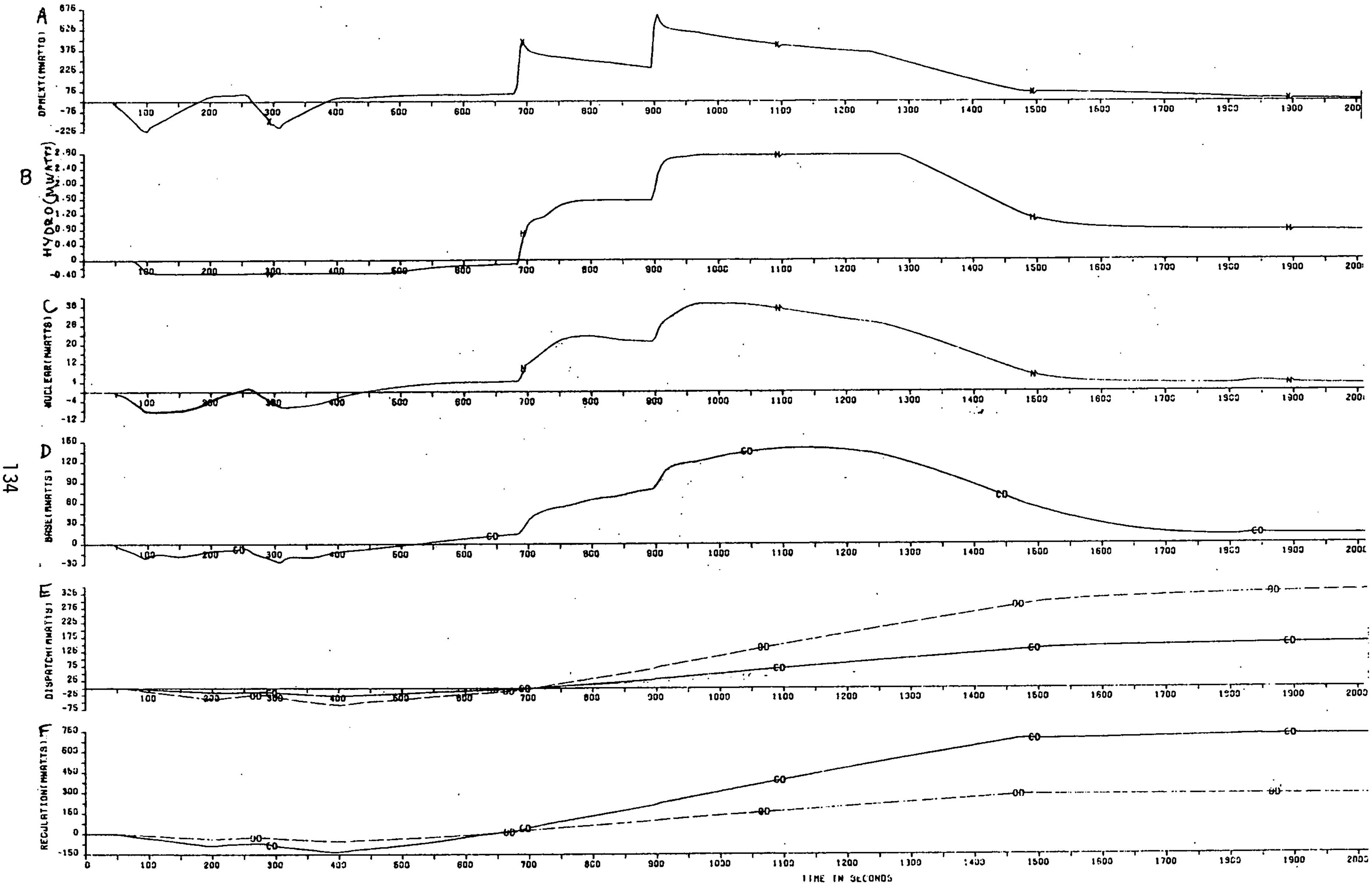


Figure 38 Generator Responses for Morning Pickup #2

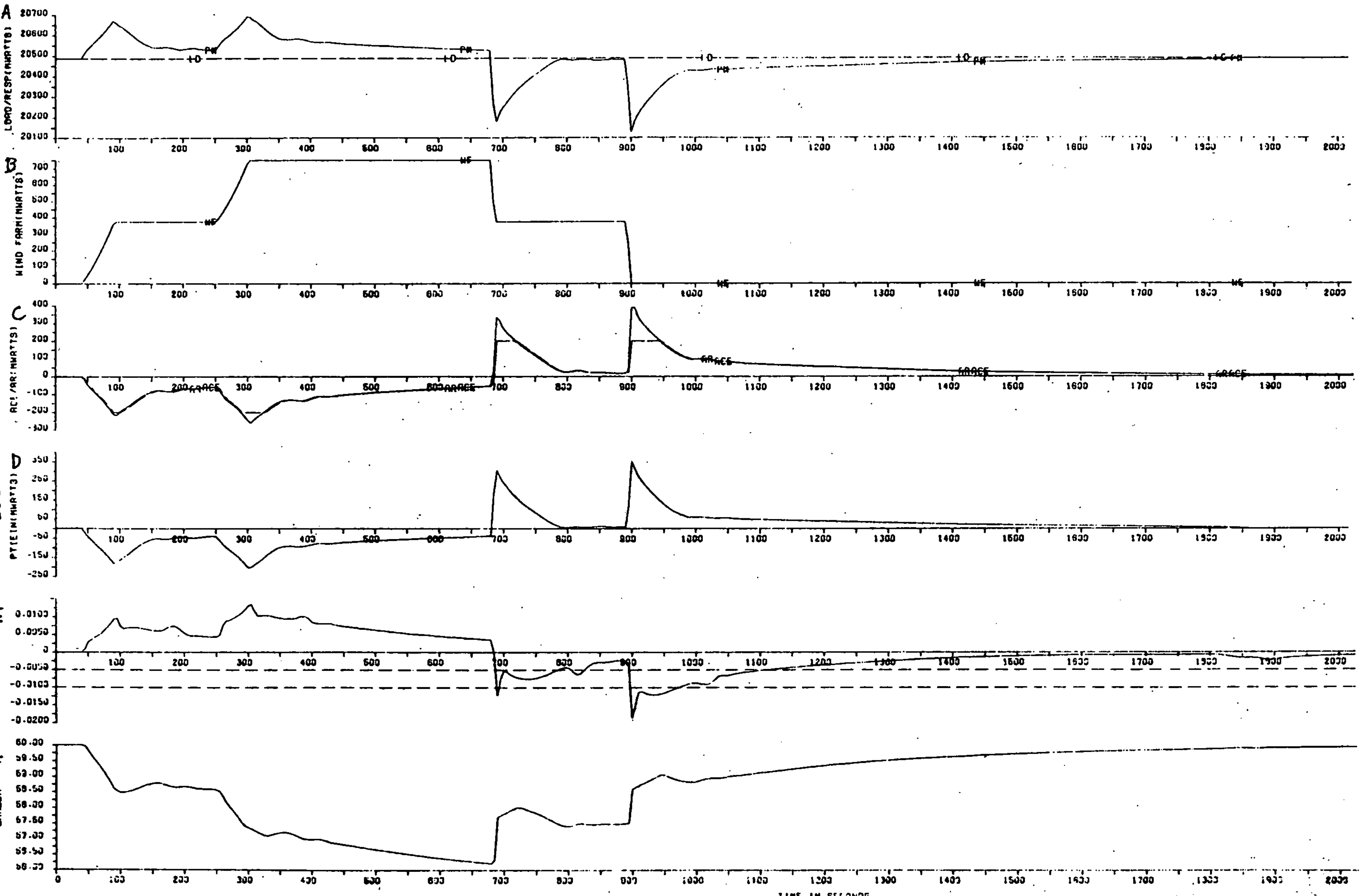


Figure 39 Summer Peak with Coastal Farm and no Load Variation

for the increases in generation on both coastal farm WTG echelons. Similarly the area control error and tie line power show very sharp increases and a slow decay toward zero after each shutdown of an WTG echelon. The frequency deviation, shown in Figure 39E, differs slightly from area control error and tie line power signals in that

(1) there is a sharp spike on the frequency signal at its minimas for wind generation increases, and maximas for wind generation decreases. These spikes are due to the rapid but very limited governor frequency regulation controls that act to reduce the frequency deviation due to any change in load or generation.

(2) the frequency signal has more oscillatory behavior than tie line power or area control error.

The base load and nuclear base loaded unit, shown in Figure 40D and 40C respectively, respond very similarly to the frequency deviation signal. The hydro regulation unit responds like the area control error signal. The economic dispatch units (OD, CD), shown in Figure 40E, respond slower to the wind generation changes than does hydro. Moreover, the change in generation continues to decrease long after the initial wind generation increases in order to compensate for the power on the regulating units and the power due to frequency regulation controls backing away from the initial decreases taken immediately after the wind generation increased. A similar effect is observed on these economic dispatch units after the wind generation decrease but in the opposite direction. The regulation and economic dispatch units, shown in Figure 40F, experience a change immediately after the wind power change but do not experience any change in the intervals between these changes due to the fact economic dispatch cancels the effects of governor frequency regulation and automatic generation control regulation during these intervals.

The frequency regulation and AGC controls are able to compensate for the wind power variations from a 3.75% farm quickly

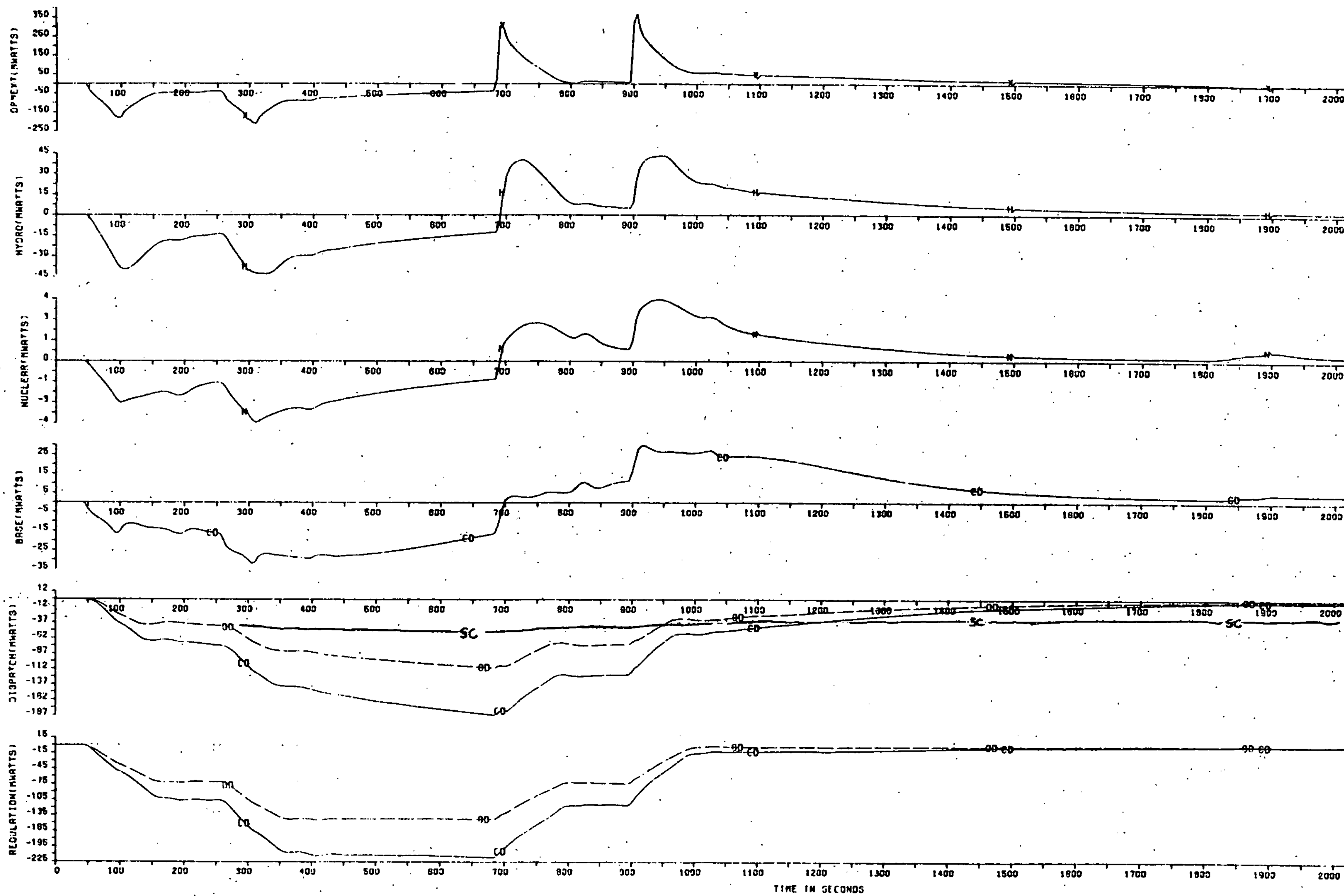


Figure 40 Generator Responses for Summer Peak with the Coastal Farm

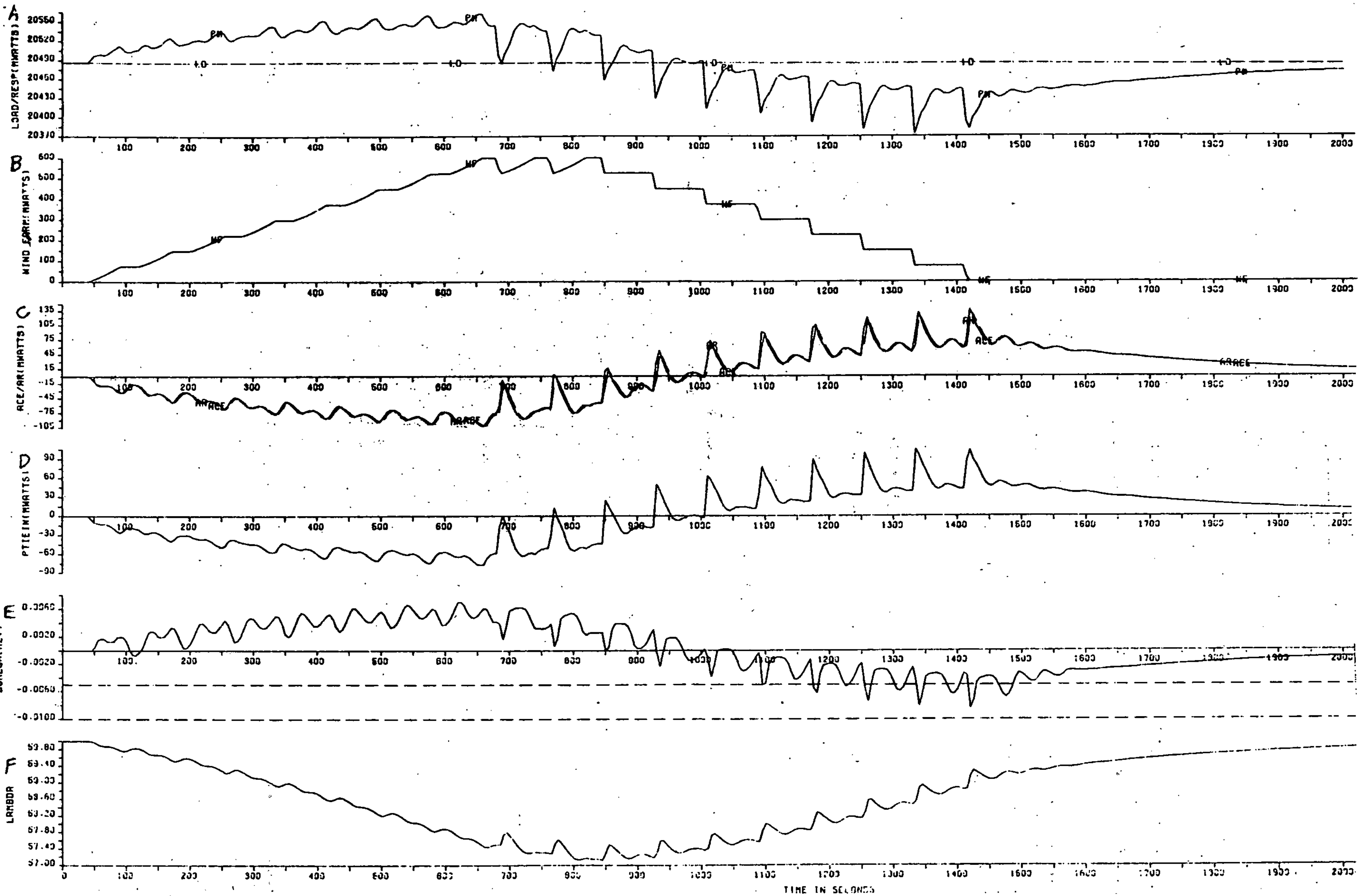


Figure 41 Summer Peak with Midwestern Farm and no Load Variation

and without large sustained deviations in frequency, area control error or tie line power when no load variation occurs. The economic dispatch units do continue to unload the regulating units and reduce the power taken on for governor frequency regulation and several minutes after the actual changes in wind generation have occurred.

Summer Peak with a Midwestern Farm

The 20,000 MW system with no load variation and a 750 MW 3.75% midwestern farm was run

(1) to show that the peak deviations in area control error, frequency and tie line power are proportional to the generation capacity on each echelon by comparing simulation results for the coastal and midwestern farm on the 20,000 MW system and the summer peak unit commitment.

(2) to show that cycling problems can occur on nuclear units if the WECS generation capacity on any echelon is large enough to generate frequency oscillations that are larger than governor deadbands on these units

The load (LD) and mechanical power (PM) out of all generators including the wind farm are plotted in Figure 41A. The power variation from the midwestern wind farm, plotted in Figure 41B, indicates total wind power increases for approximately ten minutes as the first seven echelons have wind generation increases due to the leading edge outflow of the storm front. The wind power remains fairly constant for the next four minutes as the shutdown of the first three echelons due to the trailing edge inflow cancels wind generation increases on the last three echelons. The wind generation then gradually decreases over the next ten minutes as the high wind speeds of the trailing edge inflow cause shutdowns on WTGs in the last seven echelons. The area control error, and tie line power, as shown in Figure 41D and 41C, gradually decrease as wind generation increases but then decrease to nearly zero as the period of constant wind generation occurs because the changes in wind power generation are slow enough that AGC regulation, and dispatch as well as frequency regulation have been able to compensate for the increase in wind generation. The area control error and tie line power increase and are positive during the interval that wind generation is decreasing and then decay to zero over several minutes after wind generation stops decreasing. The frequency signal, shown in Figure 41F, is considerably more oscillatory than the area control error and tie line power signals.

Comparison of the area control error, tie line power, and frequency deviations, for the summer peak with coastal and midwestern farms indicates the changes in these signals due to the generation increases or shutdowns on the coastal farm are five times those on the midwestern farm because the capacity of WTG's in each echelon of the coastal farm is five times that of the midwestern farm. The changes in area control error and frequency are much larger for shutdowns than for the wind generation increase because the generation changes for shutdowns are so fast that governor frequency regulation can not respond. The system frequency has a spike at each shutdown which reflects the delay in governor frequency response to these rapid WECS generation change at shutdown.

The frequency signal is thus much more oscillatory than the area control error signal. The oscillations do appear on the base loaded units and base loaded nuclear units, shown in Figure 42D and 42C respectively. These oscillations or cycling of units is a severe problem and would occur whenever the echelons in a farm approach the maximum echelon capacity of 75 MW which is determined by the maximum width of a thunderstorm front and the minimum spacing between adjacent WTGs in an echelon. These oscillation would disappear if the echelon generation capacity were smaller so frequency deviations would be below normal deadband of 0.0036 hz and the governor would

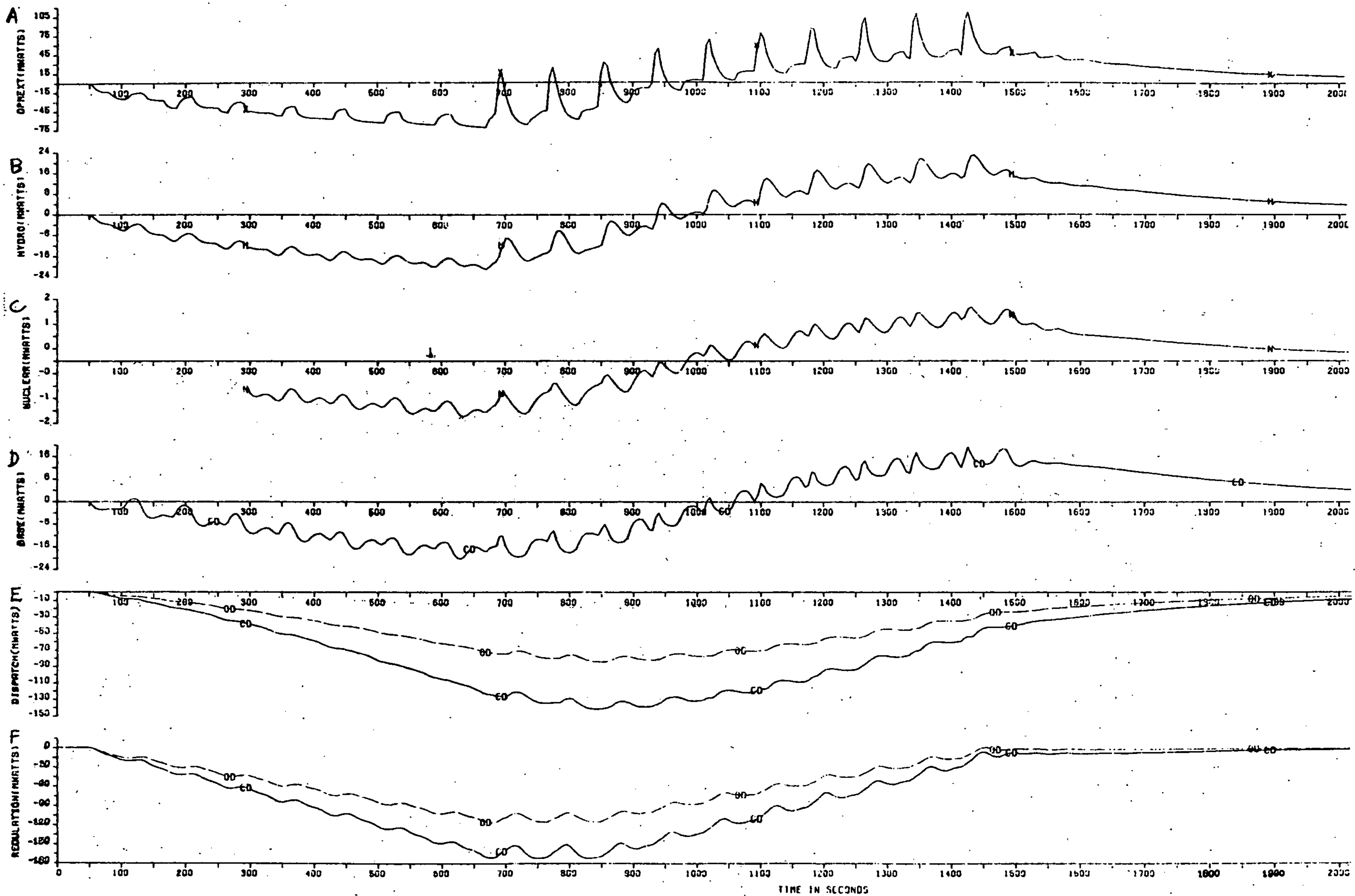


Figure 42 Generator Responses for Summer Peak with the Midwestern Farm

not be able to respond to these oscillations. Restriction of the capacity of each echelon below 50 MW would reduce the frequency oscillations and the cycling problem on this 130,000 MW internal-external PJM system model.

Restriction of echelon capacity is thus a method of reducing the cycling problem and restriction of farm capacity or requiring the siting of this generation to be distributed so that spacing between echelons is also larger would solve the AGC regulation response problem. These constraints are not attractive because they restrict the total wind generation available. Thus, other solutions to the AGC regulation response and cycling problems should be attempted if these operating problems would be a concern for a particular system and WECS generation siting configuration.

Section 5: CONCLUSIONS

The conclusions for the research performed in part 2 are

(1) a worst case thunderstorm front

- (i) has the maximum width (25 mi) and thus can affect the greatest number of WTGs
- (ii) moves at 30 mph and thus causes higher power variation rate during the leading edge outflow and affects more WTGs in ten minutes, the time frame of the spinning reserve requirements on AGC
- (iii) has wind speed below 13 km/hr before passage of the storm front so that power out of the WTG before passage of the front is zero and a maximum change in generation will occur as the leading edge outflow for the front passes
- (iv) has a minimum distance (D) between the leading edge outflow at the point internal to this outflow where wind speed reaches 26 km/hr so that power variation rate out of a WTG will be maximum

(2) a worst case wind farm siting configuration

(i) has a 0.57 mi spacing between WTGs in an echelon so that turbulence from one WTG will not affect other WTG's. A larger spacing is not used so that a maximum number of WTGs can be affected by the thunderstorm front and produce worst case power variation.

(ii) has a 0.57 mi spacing between echelons so that a maximum number of WTGs can be affected by a thunderstorm in any ten minute interval

(iii) has as many echelons as possible for the average wind speed profile at that location. A farm site on a body of water will have a limited area due to the fact average wind speed decreases with distance from the coast.

(3) the theoretical worst case farm with minimum spacing between WTGs could have a maximum of WTGs affected by a single worst case thunderstorm front in ten minutes.

(4) a maximum echelon penetration level of between 2% and 3% constrains power variation rates for a wind farm for passage of the leading edge outflow of a thunderstorm front to be less than typical power system rate capability. The echelon penetration constraint will limit the width of a WECS array if the penetration of an area D_o miles wide and D_o miles long exceeds this penetration constraint. If the penetration of this region does not exceed the echelon penetration constraint, the WECS array could be arbitrarily wide.

(5) the maximum penetration level for all the WTG's that can be affected by a single thunderstorm front (in an area D_o miles wide running the entire length of the motion of the front) must be less than the spinning reserve requirement in order to meet NAPSIC performance requirements on AGC for WECS generation changes alone.

(6) saturation of AGC regulation and economic dispatch could occur for normal spinning reserve margins set without consideration of WECS generation if large load and WECS generation changes occur simultaneously. This saturation will cause violation of NAPSIC performance requirements of AGC.

(7) the saturation of AGC regulation and economic dispatch can be alleviated if the spinning reserve margin is increased. The increase in spinning reserve margin will generally be dictated by a study of system reliability with WECS generation and not purely by the saturation problem noted here. The results that indicate this saturation problem can be eliminated by an increase in spinning reserve are very significant because they provide an expanded understanding of the spinning reserve requirements when WECS penetration is significant.

(8) a change in generation mix to include a higher percentage of fast responding units on regulation will improve AGC response to WECS generation changes if the AGC is not saturated.

(9) a cycling problem on generators in a system will occur due to WECS generation changes during passage of a thunderstorm front if the capacity of all WTGs in any echelon is large enough to cause frequency oscillations larger than the governor deadband on these generators. The capacity of an echelon had to be greater than 50 MW for this cycling to occur on the simulated system of 130,000 MW.

The study performed here was definitely worst case; both in regard to the power variations out of a farm and the effects on the operation of the power system. There would be methods to reduce the power variations from a farm that were not investigated such as sequentially shutting down WTGs in each echelon to reduce the effects of a sudden simultaneous shutdown of an echelon. The selective shutdown is done with run of river hydro units where ponding levels must be kept within prescribed limits.

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