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AUTOMATIC GENERATION CONTROL ALGORITHM - GENERAL CONCEPTS AND APPLICATION TO THE WATERTOWN ENERGY CONTROL CENTER

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16. ABSTRACT

An algorithm for computer implementation of an automatic generation controller (AGC) is described. Details of concepts with equations and flow charts are provided for FORTRAN programming. The algorithm is designed for the control center at Watertown, South Dakota, but is general in description and may be used as the basis for similar energy control centers.

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Denver, Colorado

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In May 1981, the Secretary of the Interior changed the Water and Power Resources Service back to its former name, the Bureau of Reclamation.

The algorithm contained in this report is not designed for a specific computer system but is general in nature. The algorithm has not been specifically programmed and may contain logical errors. Also, definitions of the variables are not specifically included. The user of this algorithm must not assume that all design is completed. The programmer must design the logic to fit a specific computer system and must define the variables to suit the mathematical processes and scalings required for the specific installation. This algorithm is only a user guide.

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INTRODUCTION

The improvement of an energy control center is initiated for many reasons including improved marketing management, improved security of the power system, more economical operation, and improved system control performance. Such improvements are usually centered around a digital computer complex which allows rapid access to the large quantities of data required for improved performance. The algorithm described in this report is designed to provide the real-time, closed-loop control normally designated as AGC (automatic generation control) for such a computer-oriented complex. This report does not describe the related programs such as resource management; power, energy, and generation scheduling; or man-machine interface, although the requirments of each related program for proper AGC operation are discussed. The powerplant controller is described in a separate report [3].[1]

The theory of AGC is not complicated if viewed as only a basic control concept. However, AGC is used as a tool for energy marketing and resource management, and the additional embellishments to the basic theory create a complex controller. This report does not describe the theoretical aspects of AGC although the concepts are implicit within the equations and flow charts. A companion report entitled *Automatic Generation Control - Notes and Observations* discusses the theory of AGC [12]; it also presents an extensive bibliography if additional explanation of the AGC concept is desired.

ALGORITHM APPLICATION

The general concepts of the algorithm are applicable to any energy control center. The algorithm described is specifically for the Watertown PSCC (Power System Control Center) in South Dakota. Specific routines may be deleted or added to provide the desired control for the energy marketing and resource management concepts in use in a specific control center.

[1] Bracketed numbers identify references listed in the Bibliography.

The algorithm is presented in modules which are as self-contained as possible for clarity. Every variable or constant used has a unique name. The discerning programmer will recognize that the various modules may be grouped differently and the initializing of variables may be executed by a separate routine. Many of the variables may be temporary and the same memory location may be used for several variables; it is expected that liberties of this nature will be taken to reduce storage or decrease execution time. However, the basic functions of the algorithm must not be changed.

The concept of "algorithm" used in this report refers to the concise statement of a series of logical and mathematical steps to accomplish a specific task. This concise statement is presented as a series of flow charts. The algorithm is divided into a series of "modules" which describe specific subtasks within the algorithm. "Subroutines" are used to clarify logic flow within a module. "Programs," as discussed within this report, refer to algorithms external to the AGC algorithm and such "programs" are not flow-charted. "Routines" are also external algorithms utilized for input and output of data and are not flow-charted. The "executive" is an external program which provides the necessary timing of the AGC algorithm (as well as the many other basic machine tasks) and is not flow-charted.

ALGORITHM PURPOSE

The PSCC at Watertown, S. Dak., has the responsibility to "provide suitable automatic generation control equipment and maintain responsive generation in reserve under the control of this equipment at all times in order to meet its obligation to system and interconnection requirements."[1] The ECC (energy control computer) to be installed at the PSCC will have provisions for a suitable automatic generation controller. The primary purposes of the controller are to:

- Continually balance the control area generation against the control area load.

- Maintain the net loading of the tie lines with other areas to agree with the desired scheduled net interchange, plus or minus the frequency obligation.

- Assist neighboring control areas during major disturbances.

- Assist the overall interconnected power system in maintaining accurate time.

- Effectively and efficiently utilize the available generation and other resources within the control area.

These concepts are basic to all AGC systems. In implementing these purposes, the AGC should not attempt to control the interarea power oscillations or reduce the ability of the generator governors to damp power disturbances. Further, the AGC should minimize the activity of the mechanical equipment associated with the governor. The algorithm described in this report is an implementation of these basic concepts.

The purpose of providing the algorithm in flow chart form is to show, in sufficient detail, not only the major mathematical relationships but also to indicate the operation of the various modes and the selection of the various constants. The success of the algorithm frequently depends more on these less obvious interactions than on the more obvious and generally known mathematical relationships. The algorithm is not simple and it requires a substantial investment in computer memory and time. Specifically, the ''failure detection module'' will use approximately 80 percent of the total time for algorithm execution to process the information tables. The memory required for the algorithm will consist mostly of the many and large tables used by this module. Although this data processing section seems small in flow chart form, the importance of providing adequate time and memory for the module cannot be overemphasized. The entire algorithm is the most important power application program the computer must execute and thus should be given the necessary memory and time allocations.

The algorithm is written in an effort to minimize interaction between modules rather than to minimize programming. The variables are all named uniquely. The observant programmer will realize many variables are temporary and the total memory space need not be as large as the variable count indicates. Since this algorithm was prepared before a specific computer system was chosen, the concepts remain very general. The systems designer should feel free to modify the software sequences to improve the displays and execution and to use specific computer system advantages.

SUMMARY OF THE ALGORITHM

The AGC algorithm described in this report follows the basic tie-line bias with time deviation equation to form the area control error. The formula is[2]

$$ACE = (PAS - PS) - 10B[(FA - FS) + KTS(TA - TS)]$$

where ACE is the area control error in megawatts; PAS is the sum of the actual, measured tie-line power in megawatts; PS is the scheduled tie-line power in megawatts; B is the frequency bias in megawatts per 0.1 hertz; FA is the actual, measured system frequency in hertz; FS is the scheduled system frequency in hertz; KTS is the time deviation sensitivity in hertz per second; TA is the actual measured time from system frequency in seconds; and TS is the standard time from WWVB[3] in seconds. Positive ACE implies excessive generation and causes a reduction in generation. Positive PAS and PS indicate the power is flowing out of the control area or the resulting energy is being sold. The bias, B, is always a negative number, and the sensitivity, KTS, is always a positive number.

[2] Variables are normally italicized and/or subscripted in most service reports but are written in single line and capital letters in this report to correspond to the flow chart equations and the computer algorithm format.

[3] National Bureau of Standards time standard radio station - Ft. Collins, Colorado.

The control has at least five modes. The equation for the "tie-line bias with time-error bias" mode is the one previously given. The equation for the "tie-line bias" mode is

$$ACE = (PAS - PS) - 10B(FA - FS).$$

The equation for the "constant frequency" mode is

$$ACE = \quad -10B(FA - FS).$$

The equation for the "constant net interchange" mode is

$$ACE = (PAS - PS).$$

The "suspend control" mode allows the ACE to be calculated and monitored in any mode, but control of powerplants is not permitted.

After the ACE is calculated, it may be filtered by one of three methods:

- A probability filter to remove random load fluctuations and to accentuate the slow changes of ACE [2].

- The integral of ACE added to ACE along with a simple smoothing filter to reduce the faster random load fluctuations within the ACE.

- No modification of the ACE.

The resulting ACE is then allocated to the plants through a constant gain allocator using participation factors. The plants in baseload are also allocated to allow gradual loading and unloading of a plant. The maximum loading and unloading rates of a plant limit the ramping of the plant. The entire allocator is permissive in concept and will control a generator only when an ACE requires the control. However, mandatory ramps for plant loading will be allowed if the dispatcher desires. Such ramps will be counterramped by the allocator to minimize ACE disturbance if possible. Thus, any plant may have four modes:

- Automatic allocation of ACE.

- Baseload allocation with ramps to accommodate basepoint changes only when ACE would benefit.

- Ramp control for forced generation changes with counterramping of automatic or baseload control.

- Off AGC control.

The plant controller may be implemented by a different manufacturer at the powerplant and power requirement or set point will be sent to the plant over a communication channel [3]. If there is no controller at the powerplant, a closed-loop power controller is included in this algorithm. The algorithm will send raise and lower pulses to the plant to control the power to the required set point.

The overall control may be summarized as a permissive, constant gain, predictable time response AGC system. The system is designed to reduce activity by filtering ACE, allocating reasonable changes to a plant, and by using a plant response predictor. If ACE becomes large, the ACE filters are bypassed to improve the speed-of-response of the control, but the allocators and plant controllers remain the same.

FLOW CHART CONCEPTS

Because the purpose of this report is to present a specific computer based algorithm, the remaining report sections deal with the specific algorithm equations and the interactions with other computer programs and systems. The flow charts describe explicitly the algorithm logic needed to develop computer code. The text supplements this logic with concept development to allow the programmer to grasp the needs and reasons which dictate the logic. Neither the report nor the flow charts stand alone and yet the flow charts are more than an illustration of text information. Indeed, the text discusses only the most important concepts, leaving much of the logic unexplained. In many cases, specific flags and variables are explained much later in the text to keep the concepts as uncluttered as possible. As an example, the flag FLAGSC in the power schedule module is explained near the end of the report in the Buffers section. The theory of AGC is not discussed directly in either the text or the flow-charts, and references [12] should be consulted.

This algorithm contains not only the basic concepts but includes all the parts to make a working system, and many concepts which are nice but not necessary. Although the algorithm is designed for the Watertwon ECS, the final program may not contain all of the algorithm shown in this report. However, other installations may need some of the parts which the Watertown ECS will not use. Therefore, all the algorithm is presented; it will be reduced as specific needs are addressed with the actual use of the control system.

The first flow chart, figure 1, shows the entire AGC control system in a signal flow or block diagram form. The power system governors and plant controllers are developed in references [7, 12]. The entire diagram explains the control theory and can be used to understand the theoretical limits of the control. However, the diagram is used as a roadmap through the algorithm, and the actual control theory is not addressed.

The AGC algorithm, as it relates to the computer, is shown in the first sheet of figure 2. Here, the interaction of the various programs is diagramed to provide a roadmap of external program interaction. The actual order of the modules within the AGC algorithm is shown in the second part of figure 2. The flow charts of the modules are assembled in the same order as shown on this diagram so the logic between modules may be traced. The descriptions in the text do not follow that same order because concepts, rather than logic patterns, are grouped. The following list is provided to cross-reference the flow charts by figure number and caption to the Contents.

Figure 3.-Typical data transfer techniques - Buffers, and Initialization of Constants.

Figure 4.-Power schedule module - Total Schedule.

Figure 5.-Ramp test module - Perturbation and Response Analysis.

Figure 6.-Failure detector module - Data Failure Detector, and Analog Inputs.

Figure 7.-Intertie power module - Intertie Power Measurements.

Figure 8.-Frequency module - Frequency Bias.

Figure 9.-Time error module - Time Error and Sensitivity.

Figure 10.-Instantaneous inadvertent module - MAPP Signals.

Figure 11.-MAPP coordination signal module, and figure 12, MAPP power bias module - MAPP Signals, and Plant Communication Link.

Figure 13.-ACE formation module - Summation.

Figure 14.-SHADE preparation module - Total Schedule.

Figure 15.-Emergency assist module - Emergency Assist Detector and Alarms, and Limiter.

Figure 16.-ACE integral and smoothing module, and figure 17.-Probability filter module - Filters.

Figure 18.-AGC gain module - Gain Stage.

Figure 19.–Plant data module, figure 20.–Powerplant communications link, figure 21.–Joint-owned unit data module, and figure 22.–No-response detector module - Powerplant Data and No-response Detector, Joint-owned Units, and Plant Communication Link.

Figure 23.–Ramp allocator module - Ramp Allocator, and Perturbation and Response Analysis

Figure 24.–Baseload allocator module - Baseload Allocator.

Figure 25.–Participation factor calculation module, and figure 26 Automatic allocator module Automatic Allocator.

Figure 27.–Assist allocator module - Assist Allocator

Figure 28.–Plant control module - Pulse Controller With No Feedback, Pulse Controller With Power Feedback (PID), Closed-loop Plant Controller, and Plant Pulse System.

Figure 29.–Joint-owned unit output module - Joint-owned Units.

Figure 30.–Plant response specifications - Closed-loop Plant Controller, and Plant Communication Link.

Figure 31.–Margins calculation module - Margin Calculations.

Figure 32.–NAPSIC criteria module - NAPSIC Criterion.

Figure 33.–Standard deviation module - Standard Deviations, and Frequency Domain Analysis.

Figure 34.–Generation control format module - Control Formats, Margin Calculations, and System Disturbance Detector.

Figure 35.–Strip chart output module - Engineering Evaluation Outputs and Inputs, and Permanent Strip Chart Outputs.

Figure 36.–Terminal module - Buffers, Initialization of Constants, Engineering Evaluation Outputs and Inputs, and Spare ASCII Ports.

Figure 37.–Suggested format for AGC signal flow - Control Formats.

Figure 38.–Flow chart symbol definitions - (No text discussion.)

FORMATION OF THE AREA CONTROL ERROR

The area control error is formed according to the equations given in the Summation section. The details of each quantity used by the equations are given in the following.

Total Schedule

The Intertie Schedule and SHADE

The schedule prepared by the Power and Energy Scheduling program and checked or modified by the dispatcher is

$$\mathrm{PSCHEDULE} = \mathrm{PSCHED} + \mathrm{SHADE} + \mathrm{IISCH} + \mathrm{IDISPADJ}$$

where PSCHED is the set intertie schedule which is the sum of the power to be bought and sold over an hour or any other period desired by the dispatcher. The value is in megawatts and is positive for power sold or leaving the control area. This sum is generated by the Power and Energy Scheduling program every hour or as the dispatcher makes entries. The Power and Energy Scheduling program will provide the AGC system with the current schedule desired (PSCHEDULE), the ramp time in minutes (usually 10 or 20 min) and the time desired to start the ramp. The AGC system will then generate a ramp from PSCHEDULE previous to PSCHEDULE desired, starting at the desired time of day and executing the ramp in the period specified. The ramp generator is capable of calculating new ramp rates if the desired PSCHEDULE is changed during the ramp. Further, if the dispatcher desires, a derivative value of the schedule may be calculated to modify ACE before the allocators; see the Gain Stage section.

The Power and Energy Scheduling program also calculates SHADE. A calculation flow chart is included in figure 4 although the AGC algorithm does not calculate SHADE.

Basically, SHADE is the integral of the inadvertent interchange due only to metering errors divided by the time the inadvertent was measured, and then also divided by the hour period used for each schedule setting. A SHADE setting added to the schedule produces a specific amount of energy (in megawatt hours) for every hour the setting is used. This number should balance (or be opposite to) the energy (in megawatt hours) inadvertently being interchanged because of the various system metering errors. If this balance occurs, then the inadvertent interchange due to these errors becomes zero and the integral of this inadvertent interchange (SHADE) becomes steady.

The errors are caused by inaccuracies of the frequency and power transcuders and also telemetry equipment and A/D converters. The actual energy readings (the megawatt hour readings) at the end of each hour for each interchange point is assumed perfect in the calculation of SHADE.

Because the metering errors are not directly measurable, they must be calculated. The directly measurable quantity is inadvertent interchange. This inadvertent interchange is due to errors of many kinds and includes metering errors as one component. The other components include errors in settings, errors in ramping, and the interchange resulting from attempts to restore frequency and time.

$$\mathrm{SHADE} = \int_0^T (-\mathrm{II} + \mathrm{IISCHED} + \mathrm{TIMEADJ} + \mathrm{FREQADJ} + \mathrm{PSRAMPS} + \mathrm{MAPPADJ})dt$$

where T is the period of the calculation. This period is normally 1 hour but may be as much as 24 hours depending on the selections of the dispatcher. The integration is approximated with a rectangular integration technique iterating once each hour. The hour period is most convenient for measuring the energy readings (MW·h) of the inadvertent interchange, II. The II is calculated from actual energy readings and schedules, and is corrected for dynamic schedules. The IISCHED is the average scheduled inadvertent interchange over the hour used to pay back previous inadvertent accumulations. The subtraction of II and IISCHED is the energy which is unintentional inadvertent and is not scheduled in any way.

The FREQADJ is a calculation of the energy exchanged in an attempt to return frequency and time to normal and is the average frequency schedule set point due to frequency offsets and time error corrections. The TIMEADJ is a measure of the returned energy that was unused from FREQADJ because the time was actually corrected on the system. The PSRAMPS is the calculation of the energy error resulting from the ramping of the actual schedule as opposed to the use of no ramps on the schedule when calculating II. The MAPPADJ is the inadvertent interchange due to a MAPP power bias.

In summary, SHADE is the integral of the unaccounted energy due to metering and equipment errors as compared to the metered energy, with adjustments for time correction efforts and dynamic schedules. SHADE is in megawatts.

$$\text{SHADE} = (\text{SHADE} - \text{ADJACE}) \div 1 \text{ hour.}$$

Also,

$$\text{ADJACE} = \text{II} - \text{TIMEADJ} - \text{FREQUADJ} - \text{PSRAMPADJ} - \text{IISCHED} + \text{MAPPADJ}$$

where ADJACE is in megawatt hours. The inadvertent interchange, II, is calculated at the end of each hour just after the energy readings (MW·h) are received from the intertie points. All interchange readings are required, and if any are missing or contain possible errors, an alarm should be generated so that the proper adjustments may be made by the dispatcher before calculated. It is a good practice to verify every reading each hour. The quality of the reading is also detected by the tie line calibration function of the AGC. The procedure uses the total energy of the tie line accumulated over the hour by the calibration routine; then, the Power and Energy Scheduling program reads the accumulations after the hour is completed. The accumulation is compared to the metered energy readings and if the error is larger than plus or minus 2 percent, an alarm is generated. The equations are described in the Intertie Power Measurement section. And

$$\mathrm{II} = (\mathrm{IMDEL} - \mathrm{IMREC}) - [(\mathrm{PSDEL} - \mathrm{PSREC}) \times 1\ \mathrm{h}] + \Big(\sum_{\substack{\mathrm{ext} \\ \mathrm{JOU}}} \mathrm{IJOUEXT} - \sum_{\substack{\mathrm{int} \\ \mathrm{JOU}}} \mathrm{IJOUINT}\Big) - \sum \mathrm{IPLOADS}$$

where II is in megawatt hours and positive energy is leaving the control area. The quantities IMDEL and IMREC are the summation of the energy readings (MW·h) delivered and received for every interchange point. The dispatcher should have the opportunity of verifying these readings and making substitutions if desired. The quantities PSDEL and PSREC are the total power scheduled to be delivered and received across the interties in magawatts. The joint-owned units (JOU) transfer energy across the control area boundaries which is not part of the schedule. The energy readings for external joint-owned units (JOU not in the control area boundaries) is calculated by integrating the power received from each unit over 1 hour, or

$$\mathrm{IJOUEXT} = \sum_{1\ \mathrm{hour}} \frac{\mathrm{PJOU} \times \mathrm{TIMESLP}}{3600}$$

where IJOUEXT is in megawatt hours, PJOU is the power signal received from the external "operating" utility every 2 seconds to create the dynamic schedule and TIMESLP is the time since the last pass of the AGC algorithm in seconds. Thus, IJOUEXT is calculated by the AGC algorithm and used by the Power and Energy Scheduling program. It is important to use the calculated value for IJOUEXT because use of the actual value may cause inadvertent interchange due to computer accumulation errors in the AGC computer used by the operating owner [4]. Further, if it is possible to obtain the same quantity calculated by the operating utility, a comparison can be made to prevent inadvertent interchange accumulation for either area. The IJOUINT quantity is also in megawatt hours and is calculated as

$$\text{IJOUINT} = \text{IJOUT} - \sum_{\text{external owners}} \left(\sum_{1\ \text{h}} \frac{\text{PJOU} \times \text{TIMESLP}}{3600} \right)$$

where IJOUT is the hourly energy reading from the joint-owned unit internal to the control area and PJOU is each external owner's share of the power which is transmitted from the AGC algorithm. The summation is named PJOUS in the AGC algorithm. The IJOUINT calculation is made by the Power and Energy Scheduling program. Again it is important that the calculation errors between the energy scheduled and the energy metered be absorbed by the operating owner (with the JOU internal to the control area) to eliminate inadvertent interchange. The IPLOADS is the measured energy for each internal or external dynamic load or generation, and is positive for external load or internal generation.

The frequency adjust quantity is calculated from the average frequency set point and average time error over the hour. Because inadvertent interchange is calculated once an hour, the best accuracy can be achieved by calculating the frequency set point and time error over 1 hour intervals. If the time error is used in the calulation of ACE, such as in the tie line bias plus time error mode of operation,

$$\text{FREQADJ} = (-10\text{B}(\text{FSAVE} - 60) - \text{KT}(\text{TEAVE})) \times 1\ \text{hour}$$

where FSAVE is the frequency schedule average for this hour (the hour now ending or recently ended). The TEAVE is the average time error for this hour, B is bias in megawatts per 0.1 hertz, and KT is time bias in megawatts per second. The FREQADJ is positive for positive frequency schedules (the negative sign on the calculation is due to the negative sign inherent in B and KT.) The TEAVE should be calculated only when the time error is used in forming ACE. The FSAVE should be calculated only when the frequency error is used in forming ACE. Both quantities will be available from the AGC algorithm.

If MAPP bias is used in forming ACE, then this inadvertent interchange components should also be eliminated from the quantity forming SHADE. Again the average MAPP bias over 1 hour should be used to form

$$\text{MAPPADJ} = \text{KMB} \times \text{MAPPAVE}$$

where KMB is the MAPP bias constant. The MAPPADJ will be available from the AGC algorithm.

To remove the unused interchange, which has instead caused a time correction (because all utilities participated in the interchange), a time correction adjustment is made. The calculation is

$$\text{TIMEADJ} = +10\text{B}\ \frac{\text{TIMETH} - \text{TIMELH}}{3600} \times 60$$

where TIMETH is the time error recorded at the beginning of this hour and TIMELH is the time recorded at the beginning of last hour. The 1:60 ratio (60/3600) is obtained from

$$\frac{\text{Frequency set point} - \text{60-Hz reference}}{\text{60-Hz reference}} \times 3600\ \text{s/h} = \text{time correction in seconds per hour}$$

providing all control areas use the same frequency set point. The dispatcher should be able to enter TIMETH and TIMELH into the Power and Energy Scheduling program if actual data is not available. The actual data will be available from the AGC algorithm.

The adjustment of inadvertent interchange for ramping across the hour is made by

$$\text{PSRAMPADJ} = \frac{(\text{DPSE} \times \text{TIMESCIL}) - (\text{DPSB} \times \text{TIMESCLP})}{8 \times 3600}$$

where PSRAMPADJ is in megawatt hours. The quantity DPSB is PSCHED at the beginning of the last hour minus PSCHED at the end of the hour before the last hour, and DPSE is PSCHED at the start of the present hour minus PSCHED at the end of the last hour. The quantity TIMESCIL is the length of the ramp time in seconds used in the ramp between the hour before the last hour and the last hour, and TIMESCLP is the ramp time between the last hour and the present hour. The ramp times are assumed symmetrical about the end of the hour. The quantity PSRAMPADJ is used with calculations of SHADE based on first hour's energy readings.

The dispatcher may choose to calculate SHADE over other time periods than 1 hour. These periods may be over "on peak" and "off peak" periods or over 24 hours. The integrations given for the components of SHADE may be summed over the necessary number of hours required by the dispatcher and divided by the same number of hours. The Power and Energy Scheduling program will provide these calculations for SHADE.

Finally two entries may be made by the dispatcher to manually provide schedule corrections. The first is the scheduled inadvertent interchange. The quantity IISCH is entered by the dispatcher into the Power and Energy Scheduling program. When SHADE is calculated,

$$\text{IISCHED} = \frac{\dfrac{\Sigma\ \text{IISCH} \times \text{TIMEBCI}}{1\ \text{hour}}}{3600} \times 1\ \text{hour}$$

where TIMEBCI is the time interval between changes in the inadvertent schedule in seconds as calculated in the Power and Energy Scheduling program. The second entry, IDISPADJ, is the dispatcher error correction for any errors that are not otherwise accounted for. The entry is through the Power and Energy Scheduling program.

To summarize the calculations made by the Power and Energy Scheduling program, the program must be executed every hour just after all energy readings are available, and as required by the dispatcher. (The AGC algorithm takes care of the ramps and dynamic schedules requiring execution every 2 seconds.) The program should present the next hour schedules to the dispatcher at least 15 minutes before the hour. Then the dispatcher should go through a procedure to enter inadvertent schedules (when needed), frequency set points, and other pertinent information. When the dispatcher has approved of the data, a flag FLAGSC is set by the Power and

Energy Scheduling program indicating to the AGC algorithm that the data are valid. The AGC algorithm then watches the start time of the ramp and when the start time TIMESC equals actual system time TIMEREAL, the data is transferred to the AGC algorithm variables, the ramp begins and FLAGSC is cleared. If changes are made by the dispatcher before the ramp starts within the AGC algorithm, the new data replace the old data and the old data are lost and never executed. Changes may be made any time during the hour using the same process through the Power and Energy Scheduling program. See the Buffers section. The use of the flag is one suggested method from many possible methods to transfer data between a program that runs on demand and an algorithm that executes every 2 seconds. The details of the variables used in the Power and Energy Scheduling program are not complete; only information sufficient to understand the interaction with the AGC algorithm are given in this report. It is assumed that the Power and Energy Scheduling algorithm will be designed by others.

The equation for the ramp generated in the AGC algorithm is

$$\mathrm{DPSCHED} = \frac{(\mathrm{PSCHEDULE} - \mathrm{PSCHEDX}) \times \mathrm{TIMESLP}}{\mathrm{TIMERIR}}$$

where PSCHEDULE is the schedule to be used by the AGC control from the Power and Energy Scheduling program and PSCHEDX is the schedule used during the last execution of the AGC algorithm. Also,

$$\mathrm{PSCHEDX} = \mathrm{PSCHEDX} + \mathrm{DPSCHED}.$$

The quantity TIMESLP is the time in seconds since the last execution of the AGC algorithm (usually 2 seconds) and TIMERIR is the time remaining in seconds to complete the schedule change. If TIMERIR is zero, then DPSCHED is set to zero and

$$\mathrm{PSCHEDX} = \mathrm{PSCHEDULE}.$$

The Dynamic Schedule

The dynamic schedule, PDYNAMIC, is in megawatts and is positive for power leaving the control area. This power is a continuously varying measurement from joint-owned powerplants [4]. There are two cases of control of a joint-owned plant; the plant is outside the control area, and the plant is inside the control area. The equation for the plant outside the control area is

$$\mathrm{PJOU} = \mathrm{PJOUT}\left(\frac{\mathrm{PJOUR}}{\sum\limits_{\substack{\text{all}\\\text{owners}}} \mathrm{PJOUR}}\right)$$

where PJOU is telemetered continuously to the AGC system from the operating utility. The equations for the plant inside the control area is

$$\mathrm{PJOU} = \mathrm{PJOUT}\left(1 - \frac{\mathrm{PJOUR}}{\sum\limits_{\substack{\text{all}\\\text{owners}}} \mathrm{PJOUR}}\right).$$

The quantity PJOU is in megawatts and is the contribution to the dynamic schedule. It is the power received from the external joint-owned units as one owner's share. However, it is not the power received for an internal joint-owned unit but rather the sum of all other owner's share or the power which crosses the area boundary toward the other owners. The quantity PJOUT is the actual power generated by the joint-owned unit. The quantity PJOUR is the power requirement of one owner. Unless noted otherwise, PJOUR always refers to the requirement generated by the AGC algorithm. The summation is the PJOUR for all owners. The details are described in the section, Joint-Owned Units.

The dynamic schedule is then

$$\mathrm{PDYNAMIC} = \sum_{\substack{\text{internal}\\\text{JOU}}} \mathrm{PJOU} - \sum_{\substack{\text{external}\\\text{JOU}}} \mathrm{PJOU} + \sum \mathrm{PLOAD}.$$

The data for the dynamic schedule is actually calculated in the section, Joint-Owned Units, which is associated with the allocators. Thus, the dynamic schedule for the present pass is caluclated in the previous pass of the AGC algorithm.

The dynamic schedule may also be used to account for loads or generation completely owned by another utility but surrounded by the control area. The accounting of the energy of this isolated equipment should be done in the Power and Energy Scheduling program according to the terms of the contractual arrangements. Thus, the term PLOADS accounts for internal loads and external generation by using the positive sign, and external loads and internal generation with a negative sign. Finally,

$$\mathrm{PS} = \mathrm{PSCHEDX} + \mathrm{PDYNAMIC}$$

where PS is the total schedule used, PSCHEDX is the actual set schedule including ramping, and PDYNAMIC is the dynamic schedule.

Data Failure Detector

Refer to figure 6. A common program to many of the routines within the algorithm is the failure detector. Any time data are entered continuously into the computer system, the validity of the data must be checked, the quantity scaled and limited, and alternate sources of data provided. The system must be very flexible because many data types will be used from many sources. Also, the use of the data may change as the power system network is modified. New data points will be added as new facilities are commissioned and old data points will be removed. Therefore, it is most important that a convenient method of making changes and altering data usage be developed. The system should be designed primarily for the engineer because the dispatcher will not want to know the detail necessary to manipulate the data.

The data failure detector is described as part of the AGC algorithm although it could function as a separate program. Because the AGC algorithm is extremely dependent on real time data and the problems created by erroneous data or incoherent data (all data not sampled in the same time frame) are great, the AGC algorithm dictates the primary requirements of the failure detector. Also, the program must be executed shortly before the AGC algorithm for best algorithm operation. Each computer system will have individual characteristics which favor one type of error detector over another. The detection system described here is one of many types. It is described to convey the principal characteristics required for a detector and also define the interactions of the failure detector with the AGC algorithm. Although the failure detector could be called when needed by the AGC algorithm, the method described processes all data at the start of the AGC algorithm.

The Data Gathering Process

The first process of the detector is the gathering of the data. This raw data must be read from the various inputs and converted to engineering units for the failure detector program. As the data are gathered, the error flags for the data should also be gathered. The data types include data from the A/D converters for local telemetered data and local transducers, data from local BCD (binary coded decimal) inputs, data from ASCII communication links with other computers such as the PPGC (Powerplant Generation Control) systems collecting data for the Watertown ECS. The computer routines for collecting this data are not included in this report and are not trivial. However, the routines will depend heavily on the specific computer.

The data from the A/D converters should be multiplied by a separate constant (may be greater, equal, or less than one) for each input point. The constant should convert the data to engineering units and the offset provide for transducer or telemeter offset. Normally, the offsets will be zero but occasionally, the offset provides the only method of correcting a transducer reading. The data should be obtained and scaled even if the equipment indicated an error in transmission has occurred. Along with the A/D data, the "carrier failure" contacts on all the telemeter equipment should be scanned and the state of the contacts stored in an array similar to the converted data. The array should have each failure flag set if a failure is detected, and the flag cleared if the equipment is correct. The failure detector will set all flags as a final step of the routine so that the failure to update the data can be detected and the continuous update of data is ensured. The local transducers have no failure contacts, and the failure flags should be cleared when the data are read.

The BCD data from the time-error equipment should be read every 2 seconds. The data should then be converted to engineering units and stored in the array for process by the failure detector. The contacts indicating the data are not accurate should be read into the array as any other failure detection contacts. The actual hardware will dictate the precise method of reading the data. Although the multiplying constant is not needed except to adjust the decimal point, an offset should be available.

The ASCII communication system should be implemented with two concepts. First, the data to and from the PPGC systems assume the ECS is the master of the half duplex channel. The PPGC will transmit a return message only after the ECS has sent a message. Communications with the other control areas for joint-owned units (JOU) may also be in ASCII. For JOU's external to the control area, the ECS acts as the slave and responds with messages only when a message is received. For JOU's internal to the control area, the ECS acts as the master.

The ECS transmits to all PPGC's data converted from a data buffer immediately after the AGC algorithm has completed execution. When any ASCII data are received, the data are decoded using offset amd multiplier constants and are stored into the data array for the failure detector. When the data are put into the data array, a flag is cleared indicating the data are new since the last pass of the AGC algorithm. When the failure detector processes the data, the flag is set, and if the detector processes again without new data, the flag will indicate the error.

The data from the PMSC systems will be processed in large blocks determined by the design of the communication link. There are no flags available to indicate a failure has taken place. Simply receiving the data from the PMSC master will not ensure that the data have been updated by the PMSC remote terminal unit (RTU). A possible solution is to attach a square-wave generator of very simple concept to one of the spare A/D inputs at each RTU where the data originate for the AGC algorithm. For a 2-second scan rate at the RTU, the square wave would have a frequency of 0.25 Hz and have an input voltage of plus or minus 5 volts. When this data is received into the ECS, this channel is checked for a sign change. If a sign change is present, each datum point from that RTU should have the failure flag cleared. If no change of sign is detected, each datum point has the failure flag set. The failure detector program sets all failure flags after using the data, and if any failure flag is still set at the next pass of the failure detector, the data has not been updated.

The Raw Data Errors

When the failure detector begins to process the data, two types of errors, other than communication errors, are examined. Each value in the data array is compared with an array of data saved after the last pass. If any rate of change of a datum point exceeds an individual preset limit for that datum point, the corresponding failure flag will be set. This rate of change is calculated as

$$\text{RATEFAIL} = \frac{\text{DATUMOLD} - \text{DATUM}}{\text{TIMESLP}}$$

where DATUMOLD and DATUM are the individual datum points from last pass and this pass, respectively. The failure flag for that datum point is set if

$$|\text{RATEFAIL}| \geq \text{RATEFMAX}$$

where RATEFMAX is the maximum rate. The errors detected include noise bursts in the data and failure of the A/D converter for one sample.

The second type of error are the failure limits. If DATUMMIN $\leq$ DATUM $\leq$ DATUMMAX for each datum point, no failure is assumed. If DATUM lies outside the range of the minimum datum value, DATUMMIN, or the maximum datum value, DATUMMAX, the failure flag is set. This detection is for failed transducers which have gone to the extreme limit. The rate and the limits should be coordinated to detect a transducer failure because the analog filters on the A/D inputs may allow several samples of high rate before the limit is reached. The failure should be detected at the start of the first large rate.

The data array from the last pass is updated with the new data after the two failure checks are made, even if a failure flag has been set.

The Detector

The failure detector functions to "freeze" the datum point if a failure is detected. If the "freeze" remains for a preset time, action is taken to alert the dispatcher and allow manual updating. The failure detector should function every pass of the algorithm for every datum point even though a specific datum point is not being used because of manual entries.

The detector is based on a single timer per datum point. The timer is limited to work between zero and a maximum time. If the computation with the time increment drives the timer beyond these limits, the timer is reset to the applicable limit. Thus, if $TIMEA \leq 0$, then TIMEA is set to 0, and if $TIMEA \geq TIMEAMAX$, then TIMEA is set to TIMEAMAX. This limiting is done at the end of this failure detector section of the algorithm.

If the failure flag is set for any cause for a datum point, the timer is calculated as $TIMEA = TIMEA + TIMESLP$. If the failure flag is clear, then $TIMEA = TIMEA - \frac{TIMESLP}{1.5}$. The unbalanced timing allows extra time for the "thawing" process to ensure that the failure is not continuing or "chattering." If the failure is intermittent, the timer will eventually time out rather than remaining in the timed state indefinitely.

After the new time is calculated, and the timer is limited, all the failure flags are set for every datum point. This ensures that the lack of new data in the data array will be detected, because the entry of new data will clear the failure flag.

The Data "Freeze" Process

This section of the failure detector works with the mode of operation for each point. The dispatcher should be able to select the following modes for any datum point:

1. "Off" mode to set the final datum point to a fixed value, usually zero. Some points may be set to other values such as 60.0 Hz for frequency.

2. ''Man'' mode for manual dispatcher entries. The final datum value is entered by the dispatcher and the datum remains at that value until another entry is made.

3. ''On'' mode for primary channel mode. If the primary channel is available for the data, the primary channel data is placed into the final datum point. The primary channel will always be used if the primary channel TIMEA is zero. If TIMEA is not zero, the alternate channel datum is used for the final datum point. When the TIMEA of the primary channel again becomes zero, the primary datum is again used.

4. ''Alt'' mode for the alternate channel. This mode forces the alternate channel datum for the final datum point. The timer and datum for the primary point is ignored. This is used when the primary channel is being tested or repaired.

5. ''Pri'' mode for using primary datum only. This mode is used if there is no alternate channel or if the alternate channel is being tested or repaired. The alternate channel timer and datum point are ignored.

The ''freeze section transfers the raw datum to the final datum without disturbing the raw datum. This transfer is done under the control of the mode, the timer, and the alternate channel map data.

If the mode is ''off,'' the preset value for the datum is put into the final datum and the timer and raw datum are ignored. If the mode is ''man,'' the manual entry by the dispatcher is used and the timer and raw datum are ignored. The manual value is initialized to the last value of the final datum before the mode becomes manual. If the mode is ''pri,'' the primary timer is checked. If the timer is zero, the primary raw datum is transferred to the final datum. If the timer is not zero, the final datum from the last pass is used and the raw datum is ignored. If the mode is ''alt,'' then the alternate timer is checked. If the timer is zero, the alternate raw datum is used for the final datum. If the timer is not zero, the final datum from the last pass is used.

If the mode is "on," then the primary timer is checked. If it is zero, the primary raw datum is used for the final datum. If the timer is not zero, the timer for the alternate datum is checked. If it is zero, the alternate raw datum is used for the final datum. If it is not zero, the final datum from the last pass is used. If no alternate datum channel is specified, the operation is the same as for "pri" mode.

Provisions should be made for creating either primary data, alternate data, or both using several of the raw data readings. A table may be used to allow several raw readings to be added or subtracted to obtain the final value. These tables should allow a variable number of combinations to form any one datum point and allow either addition or subtraction. Further, the total table size should allow at least two combinations for every datum point. If any one timer from all the combined data points is not zero, then the composite timer is not zero. If any one timer from all the combined data points is at maximum, then the composite timer is at maximum. This imposses heavily on memory but allows needed flexibility to modify the AGC data as the power system expands and grows.

The Mode Changer

The mode changer section looks at the timers referenced in the previous section and decides if a mode change is necessary. If the mode is "off" or "man", no action is taken. If the mode is "on", "pri", and "alt", the timer is checked. For the "on" mode, if the alternate timer exceeds the maximum time for the individual channel, the mode is switched. If no alternate channel exists, the primary timer is checked. For the "pri" mode, only the primary channel timer is checked. For the "alt" mode, only the alternate timer is checked. The mode is always switched to "hold" and an alarm is generated. The "hold" mode is not available to the dispatcher entry. The last final datum is used for the new final datum. The dispatcher may change the mode as is desired. If the dispatcher changes to the "on", "pri", or "alt" modes and the timers are at the maximum, the mode will immediately change to "hold" again. In the "hold" mode, if the primary or alternate timer returns to zero, an alarm is generated to alert the dispatcher that the data is ready for service. Only the dispatcher can change the mode to "on", "pri", or "alt." The "time out" alarm and the "return" alarm should not be sent to the dispatcher more than once every 30 seconds, in the event that several data points time out or return within the 30 seconds.

The "Soft" Limiter

The soft limiter detects when any final datum is greater than limits provided by the dispatcher. If the final value exceeds either the upper or lower limit, the value used in the CRT display blinks and an alarm is generated. Again, the alarm should not be output more than once every 30 seconds to avoid confusion if many channels exceeded limits within a short time.

The "Jump" Detector

If a raw datum point suddenly changes because of noise and then returns, the rate of change detector will be activated, the timer will time for a short while, and the signal will return to normal. However, the same effect may be present for the tripping of an intertie and the failure timers would not detect the problem. Thus, a final jump detector alarms the dispatcher and flashes the value on the CRT. This jump detector places the final value in a special array for every datum point where the timer is zero. The "off", "man", and "hold" modes are not included. The timer may be either primary or alternate depending on the mode. If the timer is not zero, the data in the special array are not updated. When the timer returns to zero, the data in the special array are compared to the present final value of the datum. If the difference exceeds a preset amount, an alarm is generated and the value is flashed on the screen.

Table Characteristics

The constants for raw gain, offset, "off" value, maximum time, maximum rate, maximum limit, minimum limit, and maximum jump are set by the engineer. The tables for combining the raw data and for alternate channels should be constructed by the engineer.

The dispatcher should have available on CRT displays the final datum for each datum point and the mode of the datum. If the mode is "hold", the mode display should flash. Appropriate colors should be chosen for the remaining modes. If the dispatcher selects a specific datum point, a separate format displaying the raw datum, the mode, the limits, and the timers should appear. The ability to change modes, limits, and enter manual datum should be provided.

The failure detector requires many tables and arrays to function but the insurance of consistent and coherent data is provided with a minimum amount of dispatcher interaction. Fortunately, the total amount of AGC data required is not excessive.

Intertie Power Measurements

Failure Detector Characteristics

See figure 7. The sum of the intertie power measurements are required to form PAS. The method of selecting which interties are to be monitored must be versatile and able to be changed as system conditions, metering points, and the number of interconnections change. Initially, only the telemetered analog readings will be used for the intertie summation, but provisions are made in the failure detector to use the data from the three PMSC systems as alternate sources of the readings in the future.

Several constants are used by the failure detector module. The first constant is the limit for failure detection, RATEFMAX. Initially the limit can be set to the initial slope of a power exponential decay with a time constant of 3 seconds and an initial value of 30 percent normal capacity. Thus, if the line normally reads 100 MW, the limit would be 10 MW/s. The next constants are the failure limits. These limits should be set to a little less than the maximum and minimum signal available from the transducer or telemeter channel. The maximum timer limit should be set to 12 seconds. If the data is bad for more than 12 seconds, an alarm is generated. Should the failure contact be restored in 11 seconds, it would take approximately 30 seconds for the timer to time out and then time back. The amount of "jump" allowed during the timing process should be about 20 percent of the normal tie line flow.

Alternate channels for reading the intertie power may be available. These alternate channels must be sampled each execution of the algorithm although the data are not used. The same failure detector must be operative. If the primary data source times out, then the alternate source is automatically used unless it is also timed out. If the the alternate data originates from the PMSC systems, the data may have a maximum transport delay of 4 seconds through all the computers and communication lines and a measurement delay of 2 seconds maximum at the RTU. The total time from the actual sampling of the data at the transducer to the use of the data within the AGC algorithm must be less than 6 seconds. Delays longer than this create serious phasing or incoherent data problems in the AGC control.

Data Delay Limits

Difficulty arises in processing data through several computing systems connected in series. Each computer must store the data as the data passes through, and passing data between the processors usually must wait on scan times. Thus, the limit of delay times for a signal become important. As the requirements demand short delays, the cost of equipment rises quickly. The 6-second limit prescribed in this report is based on the errors in coherency on a 1-cycle-per-minute signal (see Timing Constraints section).

If two identical signals with an amplitude of 1.0 per unit and no phase shift are added together (similar to summing tie line power) the resultant signal has an amplitude of 2.0 per unit and no phase shift. If one of these signals are delayed by 2 seconds, the resultant signal has an amplitude of 1.989 per unit with a phase lag from the first signal of 6 degrees. For a 6-second delay, the amplitude is 1.902 per unit with a phase shift of 18 degrees. This is an amplitude error of 4.9 percent. An 8-second delay results in an amplitude of 1.826 per unit with a phase shift of 24 degrees and an error of 8.7 percent.

At this frequency of 1 cycle per minute, the amplitude need not be extremely accurate since only control is needed and the effects of the errors will average out for the marketing and accounting procedures. A 5-percent degradation of signal and the addition of approximately 20 degrees are a reasonable tolerance within the control loop, and no more than 6 seconds of delay should be allowed.

If all signals are delayed the same amount, the amplitude will not be affected, but a phase shift within the control loop will occur. The shift will be 36 degrees for a 6-second delay and 48 degrees for an 8-second delay. In this situation, the 36-degree shift is almost a burden to the control system.

Tie Line Calibration System

A system for automatically correcting the calibration of each intertie reading will be used. Each intertie reading will be individually integrated to obtain megawatt hours. At the beginning of each hour, the integrations will be saved and the integrators reset to zero. The results of these integrations will be compared to the energy data (MW·h) for the intertie by the Power and Energy Scheduling program before calculating SHADE. If the absolute difference between the readings is less than a preset limit (initially set to 2 percent of the normal interite power level times 1 hour), a calibration factor is formed. If the difference exceeds the limit, an alarm is generated indicating a suspected bad energy reading with the intertie specified and the SHADE calculation should not be performed until the energy readings are verified. If the channel providing the readings has timed out during the past hour, no alarm or calibration factor should be generated. The integration should be made using the data after the failure detection logic. The calculated energy value (MW·h) should be available for analysis even though it is not used in the calculations. The final calibration factor should be the weighted average of the hourly calculated factors.

The calibration range of each channel should divide the power scale between the maximum power limit and the minimum power limit into 10 zones with 11 boundary values, PABOUN. Each hour the calculated energy reading should be divided by 1 hour to obtain the average measured power over the entire hour. The zone for this average power should then be found. If the flag to detect the hold mode, FPAILH, is not set, a calibration factor should be calculated as

$$\mathrm{KCALX} = \frac{\text{Energy measured for the tie line}}{\mathrm{PAILH}} \,,$$

$$\mathrm{KCAL} = \mathrm{KA(KCALX)} + \mathrm{KB(KCAL)} \,,$$

and the value placed into the zone location. The quantity PAILH is calculated by the AGC algorithm and is the tie line energy for the last hour. These constants are calculated by the Power and Energy Scheduling program. Then, for every execution of the AGC algorithm, every intertie reading should be assigned to the proper zone (after the failure logic) and the reading multiplied by KCALN of that Nth zone. The resultant adjusted reading is then used for the tie line summations. The KCAL for all zones of all interties should be initialized to one. The calibration constants should be available for change by an engineer. The constants KA and KB are calculated by assuming T, the sampling period, is one hour. The time constant, τ, is 10 hours and the d-c gain is 1. Because

$$\begin{aligned} KA &= \text{d-c gain}\,(1 - e^{-T/\tau}) \\ \text{and } KB &= e^{-T/\tau}. \end{aligned}$$

Then,

$$\begin{aligned} KA &= 0.095 \\ \text{and } KB &= 0.905. \end{aligned}$$

This selection of constant allows the calibration to be changed very slowly over a period of days and weeks, and the error in any 1 hour operation will not seriously affect the channel calibration.

Summation

All interties should be summed together to give a total metered interchange in megawatts. Finally, a manual entry for "unmetered interties" should be provided for the dispatcher and added to the total metered interchange to create the total interchange power for use by the ACE. The intertie readings may be summed according to utility groups for use by the Power and Energy Scheduling program using the tables in the Failure Detector module. There is no need to provide averaging of filtering of the summation because the failure detector efficiently removes large excursions.

A summation of the tie line powers in the "off", "man" or "hold" mode is calculated for display to give the dispatcher an indication of how much interchange is not being currently monitored.

Frequency Bias

Refer to figure 8. The frequency measurement, FA, is obtained from either a transducer near the ECS computer to monitor the "east" system frequency or the time-error equipment. The reading of the transducer is sampled by the A/D converters just as for the telemetered tie lines. The frequency deviation from the time-error equipment is in BCD. The same failure detection logic should be used as for the tie lines. The frequency for the "west" system may be telemetered. The same failure logic as for the tie lines should be used. Another source for the "west" frequency may be from communication with the Yellowtail powerplant generation controller (PPGC).

The same versatility to use alternate channel for both east and west should be provided as for tie lines. The failure rate limit should be initially 0.03 Hz/s and the maximum and minimum frequency limit should initially be 60.2 and 59.8 Hz. Two checks should be made on frequency before the failure detection logic. First, if the raw frequency on the primary data channel (or alternate if the alternate was used last pass) exceeds 60.1 Hz or goes below 59.9 Hz, an alarm should be generated indicating a frequency disturbance. If the raw frequency exceeds 60.2 Hz or goes below 59.8 Hz, the AGC should be switched to the "suspend" mode and an appropriate alarm generated. There should be no digital smoothing of the frequency signal and no calibration curve need be used. (The smoothing filter on the flow chart is for droop calculations.) The analog signal may have a filter which is equal to or less than a simple 3-second filter. All limits for the frequency and selections of modes and alternate paths should be provided as for the tie lines. A manual substitute entry should be provided when the frequency is "man." However, the control can be also changed to "constant net interchange" mode by the dispatcher should a sustained loss of frequency signal occur.

The frequency schedule, FS, should be a manual entry in hertz for the dispatcher through the Power and Energy Scheduling program.

The bias, B, is a value determined once a year from AGC operational information and is entered manually. The bias is in megawatts per 0.1 hertz and is always negative. The bias is normally set to approximately 2 percent of the yearly peak generation. Exact calculation procedures are presented in the NAPSIC manual [1].

Time Error and Sensitivity

Refer to figure 9. The system time, TA, and the scheduled time, TS, are normally determined using hardware. This hardware compares the system time determined by a clock connected to the system frequency, and the standard time decoded from WWVB signals. The output of this package is usually time error in seconds where a positive error indicates that the system is faster than the standard or that a sustained overgeneration has occurred. Thus

$$\mathrm{TIMEER} = \mathrm{TA} - \mathrm{TS}.$$

Since the equipment usually requires a long warmup and stabilization time, a contact indicating when the equipment is operating correctly is normally provided. The dispatcher can change the mode to "tie line bias with time error" at his convenience. The data are normally input into the computer as binary coded decimal (BCD). A method of manually entering the current time error into the hardware package should be provided so that when the equipment is initialized, the time error can be set to a value provided by a neighboring utility.

The equipment often develops a frequency deviation signal in BCD as well as time error. Such a frequency deviation signal can be used by the AGC for the frequency input but an alternate source of frequency signal (or redundant time error equipment) must be provided. The same limits and failure detection logic should be used for the BCD input as used for the analog frequency transducer.

The time error is usually limited to a maximum or minimum value to ensure that a large time error does not unnecessarily bias the ACE. This limit is usually set to plus or minus 5 seconds but should be adjustable. The limit theoretically should be the same for all AGC systems that share interties to keep the inadvertent interchange from accumulating. The time-error constant, KT, converts the time error to megawatts and has the units of megawatts per second. This quantity

KT is the product of the bias, 10B, and the sensitivity, KTS, in hertz per second, and is always negative because B is negative. All interconnected areas should use the same sensitivity to avoid inadvertent interchange.

If a 3-second time error is to be corrected in 5 hours,

$$\mathrm{KTS} = \frac{(\text{Time error in seconds})(60\ \mathrm{Hz/s})}{(\text{Hours for correction})(3600\ \mathrm{s/h})}$$

$$\mathrm{KTS} = 0.01\ \mathrm{Hz/s}.$$

MAPP Signals

Refer to figures 10, 11, and 12. The Mid-Continent Area Power Planners (MAPP) coordination center in Minneapolis, Minn. may send signals to the ECS computer in the future. These signals will come over computer-to-computer links using ASCII aynchronous transmission. The actual signals have not yet been specified but two possible signals should be recognized for future implementation.

Inadvertent Interchange and Time Error Coordination

The first signal is an inadvertent interchange and time-error coordination signal that is in hours [5]. The modules described for this signal will not be included in the algorithm. The description and flow charts are included for future reference. The signal should be sent every hour and the failure of the signal should be determined by the fact that it had not been received by 15 minutes after the hour. A manual entry should be provided to allow the dispatcher to use a number provided by phone. The useful signal limits should be 1 hour minimum and 24 hours maximum and be adjustable by the dispatcher by hours. If a zero is either transmitted or manually entered, the signal processing logic (to be described below) should be removed from the summation of the ACE.

The signal would be used to automatically calculate the time error sensitivity as

$$KT = \frac{10B}{60\ KMAPP}\ MW/s$$

where KMAPP is the MAPP coordination signal.

Also the signal would be used to provide a bias for inadvertent interchange. The inadvertent interchange would be continuously computed from the integral of the difference between the actual interchange. Thus

$$IIC = \int (PAS - PS)dt$$

where IIC is the computed, instantaneous inadvertent interchange in megawatt hours and dt is in hours. Positive IIC implies that excess generation has taken place. The quantity PAS is the sum of the intertie measurements after the failure detection logic and metering correction factors. The metering correction factors are extremely useful in this computation. The value of PS is the actual schedule including the dynamic schedule and SHADE. When the inadvertent interchange is calculated by the Power and Energy Scheduling program (as soon after the hour as possible), the value should be substituted into the integral to reinitialize it. The value of the integral should be stored at the end of each hour and when the inadvertent interchange is calculated, the present value of IIC (which is several minutes into the hour) should be subtracted from the value of IIC at the start (or end) of the hour. Then this difference is added to the value of II. This dynamic II should be divided by the MAPP signal KMAPP giving a power bias to ACE.

The coordination signal depends on the mode sent by the MAPP coordination center. As a part of the message from the MAPP center, the mode of the signal should be transmitted. The two modes are "off", implying the signal is not for use, and "on", implying the signal is ready to be used. The ECS should transmit back to the MAPP center any information required by MAPP and the mode of the use of the signal which may be "off" implying the signal is not in use and "on" implying the signal is in use.

Power Bias

The second signal type which may be sent from the MAPP computer is a power bias. This bias would be directly added to the ACE, and would represent a continuously changing loading bias for the control area in relation to other areas. The signal would be transmitted every 2 seconds from MAPP and monitored by the normal failure detector. A mode of "off" and "on" would also be transmitted. The signal would be limited and multiplied by a constant, KMB, before being used by the ACE. The MAPP bias signal would then be

$$\mathrm{PMB} = \mathrm{KMB(PMAPP)}$$

where PMAPP is the transmitted bias in megawatts and a positive value will lower generation. It should be realized that special accounting procedures would be required with this signal because the signal forces inadvertent interchange to occur.

Summation

Refer to figure 13. The general equation for ACE for "tie line bias with time error" mode is

$$\mathrm{ACE} = \left(\mathrm{PAS} - \mathrm{PS} + \frac{\mathrm{IIC}}{\mathrm{KMAPP}} \right) - 10\mathrm{B}\,(\mathrm{FA} - \mathrm{FS}) - 10\mathrm{B} \left(\frac{1}{60\ \mathrm{KMAPP}} \right) (\mathrm{TIMEER})$$

where PAS is the sum of the interchange readings after the failure detection logic (and calibration, if provided,) and includes a manual entry for "unmetered interties." The value of PS includes the fixed schedule, the dynamic schedule, and SHADE. The value IIC is the integral of PAS minus PS. The value KMAPP is the MAPP coordination signal. The bias, B, is negative and in megawatts per 0.1 hertz. The value FA is the actual system frequency after failure detection logic, FS is the frequency schedule set by the dispatcher, and TIMEER is derived from time-error equipment.

If the MAPP signal, KMAPP, is zero, then

$$\mathrm{ACE} = (\mathrm{PAS} - \mathrm{PS}) - 10\mathrm{B}(\mathrm{FA} - \mathrm{FS}) - \mathrm{KT}(\mathrm{TIMEER})$$

where KT is the time sensitivity factor in megawatts per second. If MAPP sends a power bias signal instead of the KMAPP, then

$$\mathrm{ACE} = (\mathrm{PAS} - \mathrm{PS} + \mathrm{PMB}) - 10\mathrm{B}(\mathrm{FA} - \mathrm{FS}) - \mathrm{KT}(\mathrm{TIMEER}).$$

If the "tie line bias" mode is selected, then

$$\mathrm{ACE} = (\mathrm{PAS} - \mathrm{PS} + \mathrm{PMB}) - 10\mathrm{B}(\mathrm{FA} - \mathrm{FS}).$$

Notice that if time error is not calculated, the MAPP coordination signal cannot be used. If the MAPP bias is not being received, then

$$\mathrm{ACE} = (\mathrm{PAS} - \mathrm{PS}) - 10\mathrm{B}(\mathrm{FA} - \mathrm{FS}).$$

For the "constant frequency" mode,

$$\mathrm{ACE} = -10\mathrm{B}(\mathrm{FA} - \mathrm{FS})$$

and no MAPP signals are used. For the "constant net interchange" mode,

$$\mathrm{ACE} = \mathrm{PAS} - \mathrm{PS}$$

and again, no MAPP signals are used. When the "suspend" mode is used, ACE is calculated according to the last active mode in use (initially the "tie line bias" mode) as a monitor of activity.

No generator controls are sent to the plants. Finally, an "out-of-service" mode should be available to completely disable the algorithm from execution. This mode should be used only by the software maintenance personnel to allow making changes in the program without totally removing the algorithm from the executive queue.

The value of "raw" ACE should be displayed for the dispatcher and also recorded on a strip chart as a permanent record as suggested by NAPSIC. Also recorded on strip chart recorders should be the "Net Interchange" or PAS, and system frequency (this may also be recorded directly from the transducer). The modes of ACE may be selected from a CRT display which indicates the various paths that can be used to form the ACE. Symbols similar to breakers in a switchyard allow the various paths to be used.

MODIFICATION OF THE AREA CONTROL ERROR

After the "raw" ACE is formed, some detection systems, modifications, integrations, and gain adjustments should be performed.

Response to Area Control Error

The generators are required to respond to two activities of the area control error. The first activity is the slow system movements due to average load shifts as the power system loads and unloads in a daily cycle. These shifts are usually slower than the variations found in a 2-minute-per-cycle sinusoidal variation. Normally the governors can follow these variations without difficulty. The second activity of the area control error which requires a response is the sudden shift in ACE due to loss of a large load, tie line, or generator. These disturbances may require that several governors respond together to obtain a rate of change of power sufficient to reasonably offset the disturbance. The number of generators responding should be reduced as soon as the area control error begins to return to normal. This is usually called "emergency assist." The nature of ACE during a disturbance is usually a sudden large offset. The most that can be expected of the governors (with dashpots bypassed) is a substantial response in 15 to 20 seconds. This is approximately equivalent to the initial rise in a sinusoidal waveform of 1 cycle per minute.

Emergency Assist Detector and Alarms

Refer to figure 15. The emergency assist level of "raw" ACE should be set above normal raw ACE activity but within range of a serious disturbance. An initial setting will be plus and minus twice the maximum allowable ACE[4] under normal conditions as suggested by the NAPSIC operating criteria [1]. When the raw ACE exceeds the limits, the gain (used later in the algorithm) should be changed as

$$\text{GAIN} = \text{GAINN}\left(\frac{\text{ACE}}{\text{ACE level for emergency assist switch}}\right)$$

where GAINN is the gain used for normal activity. This gain equation essentially provides a square of the error control. It is important that ACE not be increased so that the filters and predictors that have been selected for use will respond in a normal manner. An alarm should be generated indicating an emergency assist is in progress. Also, a flag should be set to indicate to the filters and the allocators that the emergency assist is in progress. The flag may be cleared at the beginning of each algorithm execution.

Limiter

Refer to figure 15. After checking for the emergency assist, a maximum limit should be placed on the ACE. This limit serves the purpose of limiting the maximum gain on the system and also limits the dynamic range required by the filters. When raw ACE exceeds this limit, then

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[4] The maximum allowable ACE is designated as L_d by NAPSIC and is equal to 0.025 times the greatest hourly change in the net system (native) load with 5 MW added after the product is formed. This value is determined annually.

$$ACEA = ACEMAX$$

depending upon the sign of the ACE. Otherwise,

$$ACEA = ACE$$

The limit will initially be set to 2.2 times the ACE level for emergency assist or 4.4 times the maximum normal ACE suggested by NAPSIC. The limiting ACE will provide generation change five times stronger than the change at ACE level for emergency assist. An appropriate alarm should be generated.

Filters

Refer to figures 16 and 17. Three possible paths are available for the ACEA as chosen by the dispatcher. They are:

1. No filtering.
2. Digital smoothing filter with the integral of ACE.
3. Probability filter.

These filters are available to reduce the activity of the governor commands by removing the random load disturbances. The filters do not provide any "improvement" of the overall control effort but do provide for varying amounts of activity of the governors. With no filtering, the activity is at a maximum.

The Digital Smoothing Filter

The digital smoothing filter is useful for removing rapid, random load variations that are reflected in the ACEA. The time constant should be set to about 20 seconds and the gain should be set to one[2].

The equation is

$$\text{ACEB} = (\text{gain})(1 - e^{-T/\tau})(\text{ACEA}) + (e^{-T/\tau})(\text{ACEB})$$

where T is the time period between algorithm executions in seconds, and τ is the time constant in seconds [13]. For, gain = 1, T = 2 seconds, $\tau = 20$ seconds. Then

$$\text{ACEB} = (1 - e^{-2/20})(\text{ACEA}) + (e^{-2/20})(\text{ACEB}).$$

The quantity TDSF is $e^{-T/\tau}$ and if TDSF is set to zero, the digital smoothing filter is removed. A dead band for ACE is also used ahead of the filter, although the dead band will initially be set to zero.

When the emergency assist flag is set then

$$\text{ACEB} = \text{ACEA}.$$

This condition should remain for at least 120 seconds after the emergency assist is cleared before the filter becomes active again. This allows the control to recover from the emergency assist gain change before filtering out random noise again.

It is often beneficial to use the integral of ACE with ACE to form a composite signal. Although the integral of ACE has the same composition as the MAPP coordinated inadvertent interchange and time-error correction for ACE, the limits and reset functions used with the integral of ACE add to the control flexibility. The integral of ACE should be limited by a non-windup limit so that sustained offsets due to time errors or frequency errors are limited and respond immediately to trends opposite to the limit. Also, the integral of ACE should have a windup limit set about 0.75 times the non-windup limit. The integral should then be multiplied by a constant. If the constant is zero, no integral of ACE is used. A reset is also provided for the integral of ACE to allow the integral to return to zero if the integral is offset for long periods of time from some abnormal condition. The reset time is calculated as

$$\mathrm{TIRS} = \frac{T}{\tau}$$

where T is the sampling period in seconds (2 seconds) and τ is the reset time initially set to 900 seconds (15 minutes). If TIRS is set to zero, the reset function is removed.

The Probability Filter

The probability filter [2] is a most difficult filter to understand. However, a correctly tuned filter can greatly reduce governor activity with only a small increase in ACE magnitude. The filter attempts to recognize three types of ACE signals that need control and tends to reject the remaining ACE signals as "probably not needing control." For these rejected signals, the ACE naturally returns toward zero and needs no control. The three types are:

1. The ACE which does not cross zero after a preset time.
2. Average signals which move away from zero at a medium rate and have a larger amplitude.
3. Slow moving averages of ACE about zero which require correction.

The setting of the filter is somewhat arbitrary since the benefit cannot be measured in "better" control but rather in "quiet" control. Unfortunately, each person has a different idea of what these terms mean. Each of the three elements which detect the three different types of signals work independently. The output of the filter is simply switched on and off by these elements. Thus, the filter elements determine only when the filter is open (ACEP = ACEA) or closed, (ACEP = 0). Since the predictor stages and allocators would not benefit from gain changes (i.e., ACEP = 2 ACEA for some conditions), only a gain of one need be provided for all three elements. Each filter element is independent and several elements may be open at a given time. However, the output for the total open filter remains ACEP = ACEA. Each element closes by sensing a "zero crossing" of the controlling variable.

The first element opens when ACEA does not cross zero for a specific length of time, and closes when the ACE has just crossed zero. The timer will initially have a limit of 60 seconds.

For the second and third element, the integral of ACE must be formed. The integral is $IACEP = \int ACEA\ dt$ where the integration may be the rectangular type, dt is in seconds, and ACEA is in megawatts. This integral is not reset except when it is initialized to zero at power-up.

The integral has a limit. The limit stops the "windup" action of the integral and acts as a hysteresis effect for the filter. When IACEP exceeds the maximum or minimum limit, IACEP itself is set to the limit and the integral is stopped until ACEA reverses.

Both of the remaining elements are constructed the same but have different constants. Each element generates the equation

$$A = K(ACEA) + IACEP.$$

The A is compared to AMAX as

$$|A| \geq AMAX$$

and when $|A|$ exceeds AMAX for a preset time limit, the filter opens. The filter closes when A changes sign. The elements are initialized as though A has just crossed zero. It is important that IACEPM, the integral of ACE limit, is never larger than the AMAX of either filter element.

When an emergency assist is flagged, the filter is opened and is closed a preset time after the flag is cleared. This allows the emergency assist system to stabilize before being blocked by the filter. The time limit will initially be set to 120 seconds.

The initial constants for the filter elements are:

1. Element 1, time limit of 60 seconds.

2. Element 2, for moderate ACE changes; $K_A = 30$ seconds; $AMAX = 100\ L_d$ megawatt seconds; time limit = 4 seconds.

3. Element 3, for slow ACE changes; $K_A = 50$ seconds; AMAX = 100 L_d megawatt seconds; time limit = 10 seconds.

4. The integral limit is 60 L_d megawatt seconds. The value of L_d is found from the information in the NAPSIC manual [1] for operating criteria. See footnote 4 in the Emergency Assist Detector and Alarms section.

ALLOCATION OF THE AREA CONTROL ERROR

The allocation of the area control error is the most difficult concept in the AGC system. The reason for the difficulty does not lie in control theory problems or implementation of any concept but rather in the contradictory operational requirements of the generators and the AGC. The control concept for AGC indicates that the best control can be obtained if no generator changes output unless required to do so by the area control error. However, some generators operate more efficiently if the generation can be quickly moved through a certain load range and then maintained at a constant level. There may also be conflicts between water requirements of the Missouri River and the rate of loading of the plants.

Many methods have been used to resolve this conflict, but the results remain essentially the same. If a generator is forced to change generation when ACE does not require the change, the ACE will be disturbed unless a generator with identical characteristics moves in the opposite direction at the same time. This "counterramp" or opposite movement is possible to realize in a powerplant where two generators of very similar type and response can be ramped opposite one another. The concept can be extended somewhat if a power controller which forces a predictable power response is used on generators of different types. Such a concept has been designed for Grand Coulee Powerplant in Washington [6, 7], and can be used by other powerplants as well [3, 14]. The same concept can be used among several powerplants but the response of the plant cannot be as completely controlled because of communications limitations, and thus, some ACE disturbance will result.

Other constraints also enter into the allocation process which hinders the completely permissive AGC system. The dashpots on the hydroelectric governors are usually bypassed for generation changes from AGC. It is not good for the stability of the power system to have more dashpots bypassed than necessary because the bypassed governor system relies on other governors in the system for damping energy. (This concept is also true if a governor is adjusted for faster response than the governor can tolerate for an isolated load.) Thus, the allocator should attempt to have a minimum of dashpots open at any time. The dashpots close after a preset time following a pulse or a power requirment change. The closure time is usually 20 to 30 seconds.

The operational desirability of maintaining a generator at a "baseload" generation value also constrains the allocator. If the generation at a plant drifts below the baseload because of a head or fuel fluctuation, and the ACE requires primarily decreasing generation, the generator will not be returned to the basepoint for a long period of time. Some operators consider this a sign of poor AGC control.

In view of these examples, the allocation process to be implemented in the algorithm is built around four allocators, each using a different allocation technique and each serving a different purpose. Ahead of the allocators is a gain stage to control the overall gain of the AGC system. The four allocators are:

1. The allocator for mandatory ramps and set point control with counter ramps from other plants.

2. The allocator for baseload units which may be ramped as ACE requires.

3. The allocator for plants on automatic control which utilizes participation factors.

4. The emergency allocator to take care of ACE which cannot be assigned to a plant by the first three allocators.

These four allocators are executed in order. The modes for the plant control are:

1. "Ramp" for plants requiring mandatory ramps and basepoints. A power basepoint, ramp length, and ramp start time are entered by the dispatcher through the Generation Scheduling program.

2. "Baseload" for plants which may be ramped as required by the area control error. The power basepoint, maximum and minimum ramp rates, and basepoint change time are entered by the dispatcher through the Generation Scheduling program.

3. "Automatic" for plants designated to control the area control error. These plants "participate" in controlling the area control error using participation factors.

4. "Off" for plants that are not to have any control or allocation.

A possibility exists to add a "standby" mode in the future for plants that are "off" but can be switched to "automatic" during an emergency. Present operating practices do not require the "standby" mode.

Gain Stage

Refer to figure 18. Before the filtered ACE can be used in the allocators, a gain control must be added. The use of the speed-level motor as the integrating stage has been eliminated by the use of closed-loop power controllers around the plants. The concept of the power controller is presented in the Plant Control section. Because the integration stage is necessary to the AGC, the integrator must be placed elsewhere in the control chain. In this algorithm, the integrator is incorporated at the front of the plant controllers. Another function of the speed-level motor in early AGC systems was to provide the "gain." Thus, a certain number of megawatts of ACE would be converted to a number of megawatts-per-second change in plant power. The closed-loop power controllers also remove this gain effect and the new integrators have a gain of 1 second. Thus, the gain stage essentially converts the ACE from a megawatt error signal to a megawatt-per-second signal, or the rate of change of power for the plants to satisfy the area control error. Adjustment of this gain changes the response time of the AGC system. If the gain is low, the response will be sluggish. If the gain is too high, the AGC system may cause oscillations. Thus, the gain is a very important variable. The equation is

$$\mathrm{ACERATE} = -\mathrm{ACE} \times \mathrm{GAIN}$$

where GAIN is the gain with the units of 1 per second. The emergency assist detector changes the gain during period of high ACE. An initial gain of 0.033 per second gives a change of generating power of 2 megawatts per minute for each megawatt of ACE. The resulting ACERATE is allocated to the generators. The change of sign provides for the fact that positive ACE must produce a reduction in generation.

The feed forward of the schedule ramps is included in the gain routine. The rate of change of the ramp is calculated and added to the ACERATE. After all possible plants have been allocated, no more can be done and the remaining allocation is discarded. If the remaining allocation is larger than the AGC system minimum rate, an alarm is generated indicating the allocator is at the limit of operation.

Powerplant Data and No-Response Detector

Refer to figures 19 through 22. Before the powerplants generation can be allocated, the data coming from the powerplants must be updated. This is done by checking for the powerplant controller type and updating data according to the type. The various types are detailed later.

1. The pulse controller and PID controller must have the plant power updated. No other information is available.

2. The closed-loop controller is associated with a computer system at the powerplant, usually referred to as the PPGC (powerplant generation controller). If the data for maximum and minimum plant rates and capabilities are not available from the PPGC, the values are entered by the dispatcher through the Generation Scheduling program.

The no-response detection for each plant is based on error integration procedures. An error is formed by subtracting the actual plant power from the plant reference after the plant reference has been filtered by a 20-second filter (to approximate the response of the plant). The resulting error is then filtered by a 10-second filter to remove noise and add a small delay; the absolute value is determined. The result is an error from the plant expected generation. The direction of the error is determined and the error is integrated with the direction used to change the integration direction. Increasing errors increase the error integral and decreasing errors decrease the integral. If the error remains within a dead band of 2 percent of the plant maximum capability, the error integral is set to zero. If the error integral becomes greater than five times the maximum plant energy capability per second (units of megawatt-seconds), allocation to the plant is stopped until the plant controller can correct the situation. If the error integral becomes greater than 50 times the maximum plant energy capability per second, an alarm is generated and the plant is set to the "off" mode.

A special case occurs for the plants with a pulse controller and no feedback. The allocator does not use a reference and errors cannot be detected with a difference from reference. Therefore, the desired plant rate is used as a reference and the actual rate of change of power is used as inputs to the no-response detector.

Ramp Allocator

Refer to figure 23. The ramp allocator is first in the series of allocators because any activity in this allocator requires a counter-response of the remaining allocators. The ramp allocator is based on the assumption that a generator must be held at a constant set point or ramped at a constant rate and cannot participate in any way with the area control error.

The ramp allocator should be used as little as possible because such generation movements do cause the ACE to change. The plant responses for the "counter movement" are never identical to the ramping plant. The mode is very useful for testing plant response, communication links, and other maintenance problems as well as maintaining a plant at a given set point because of water, fuel, or generator auxiliary equipment restrictions.

The allocator is simple in concept. At the time requested for the start of the ramp, the plant power requirement (not the actual generator power), PREQ, is compared to the set point, PSTPT, and the generator rate given to the plant controller is:

$$\mathrm{PRATE} = \frac{\mathrm{PSTPT} - \mathrm{PREQ}}{\mathrm{PRMPT}}$$

where the sign of the desired rate is set positive if the set point power is higher than the present plant power requirement. This continues until the ramp time in seconds, PRMPT, changes sign. Then the PRATE is set to zero. The rate for the remaining ACE allocation is

$$\mathrm{ACERATE} = \mathrm{ACERATE} - \mathrm{PRATTOT}$$

where PRATTOT is the total rate found by summing the rate for each generator in the "ramp" mode. This produces the necessary counterramp. Some limit checks are included to maintain the ramps below the normal maximum ramp rates and the normal plant power limits.

Baseload Allocator

Refer to figure 24. The baseload allocator is the second allocator because the ramps for the baseload plants should be accommodated before the plants on automatic are asked to change. This reduces the activity of the "automatic" plants. The baseload plants can participate in the counterramps.

The dispatcher, through the Generation Scheduling program, provides:

1. The minimum desired loading or unloading time. The actual time will be much longer and depend on the ACE available.

2. The new basepoint desired.

3. The time when the basepoint should change.

The allocator first checks for the raise or lower inhibit based on the direction of ACERATE and ignores plants with the inhibit set. Then the plant reference (not plant power) is compared to the basepoint. If a movement in the correct direction is possible, the percent of power error compared to the normal plant capacity is calculated; then the necessary rate is calculated. The plant farthest from the set point is selected. If the dashpot or dashpots at the plant are open, the plant has a higher priority than a plant with the dashpots closed. This maintains a minimum of open dashpots. The chosen plant is then allocated a share of the ACERATE up to the maximum the plant can use, a new plant requirement is calculated, and the ACERATE is reduced. If emergency assist is in progress, the emergency rates are used. Each plant on baseload is used once in this procedure. Any remaining ACERATE is handed to the "automatic" allocator. The maximum rate allowed for each plant is calculated from an inverse solution of the plant rate filter.

Automatic Allocator

Refer to figures 25 and 26. The allocator for the plants on automatic use participation factors to distribute the remaining ACERATE. These "participation" factors are used to define the starting point for the allocation. They are used to allow the plant farthest from a limit or the plant that dispatcher wishes to favor to have the most allocation. This also allows for future economic and water dispatch algorithms to have a method of controlling the allocation. The participation factors are provided by a manual entry from the dispatcher though the AGC Display Input program or by the following algorithm. The following algorithm allows the plant allocation to "float." Allocation is on the basis of the plant farthest from the limit.

The upper and lower normal power limits of each plant are subtracted to provide the power range available to the plant. Then the raise participation is

$$\text{PARTR} = \sum_{\text{plants on auto}} \frac{\dfrac{\text{UPPER POWER LIMIT - PLANT REF}}{\text{UPPER POWER LIMIT - LOWER POWER LIMIT}}}{\dfrac{\text{UPPER POWER LIMIT - PLANT REF}}{\text{UPPER POWER LIMIT - LOWER POWER LIMIT}}}$$

where the PLANT REF is the present plant power reference in megawatts, and the limits are provided by the Generation Scheduling program, the dispatcher or data from the various plant computers. The participation factor for negative ACERATE is:

$$\text{PARTL} = \sum_{\text{plants on auto}} \frac{\dfrac{\text{PLANT REF - LOWER POWER LIMIT}}{\text{UPPER POWER LIMIT - LOWER POWER LIMIT}}}{\dfrac{\text{PLANT REF - LOWER POWER LIMIT}}{\text{UPPER POWER LIMIT - LOWER POWER LIMIT}}}$$

If after calculation, the PLANT REF – POWER LIMIT term is negative or the upper power limit minus the lower power limit term is zero or negative, the contribution to the sum should be zero and the PART for that plant should be set to zero. If the PART for all plants is zero, an alarm should be generated, and the remainder of this allocation bypassed. During the calculations, if the raise or lower inhibit is set for a plant, the appropriate PART should be zero and the plant data should not be included in the sum. When the participation factors are entered by the dispatcher or another computer program ("man" mode), floating calculations are still made to ensure the plant does not exceed a power limit.

The appropriate participation factors should then be used to divide ACERATE among the plants on automatic. The total allocation is then summed after checking maximum rates (which may reduce the participation of a plant). Any remaining ACERATE is passed to the assist allocator.

Assist Allocator

Refer to figure 27. The final allocator is the "assist" allocator. Normally the dispatcher will provide adequate capacity to take care of the fluctuations of ACE. However, there may be times when the plants on automatic may all have inhibit flags set or may be operating at the maximum rate.

This allocator creates arrays of all plant rates available for allocation. Plants unavailable include plants "off" allocation or in the "ramp" mode, plants not responding, and plants which already have maximum allocations.

The arrays arrange the plants into the following order:

1. Rates of plants on "auto" with dashpots bypassed from the smallest rate to the largest rate.

2. Rates of plants on "auto" with dashpots normal or closed from the smallest rate to the largest rate.

3. Rates of plants on "base" with dashpots bypassed from the smallest rate to the largest rate.

4. Rates of plants on "base" with dashpots normal from the smallest rate to the largest rate.

If an emergency assist is in progress, the emergency power and rate limits for each plant are used. The order is from smallest rate to largest rate because plants with little rates left usually have already been allocated and overall plant activity is reduced. Further, the use of plants with dashpots bypassed before plants with normal dashpots maintains a minimum number of dashpots bypassed.

PLANT CONTROLLERS

The plant controller section of an AGC algorithm always forms the weakest link in the system. This weakness is a direct function of the communications link with the powerplant and the ability of the powerplant to communicate to the AGC the constraints of the generators. There are three basic types of plant controllers. The AGC algorithm will operate with any of the three systems. In all three systems, the plant controller determines if the plant requirement exceeds the plant maximum and minimum power and sets the appropriate inhibit flag.

Pulse Controller with No Feedback

Refer to figure 28. The system with the poorest control characteristics but the simplest communication is the pulse controller with no power feedback. This system uses the speed-level motors in the plant as the integrating element in the AGC concept.

A "plant allocator" which allocates the pulses to the individual generators usually exists from previous AGC systems. The greatest problem with this control is that the gain is not constant for every pulse. The governor dead bands, speed-level motor hysteresis, or changes in gain of the water columns or boiler characteristics produce an unpredictable amount of power change for each pulse.

However, many plants have such controllers, and conversion to the more predictable controllers cannot be made immediately. Therefore, a plant controller for this type of system is necessary to include in the AGC algorithm. Such plants must transmit the total plant generation back to the master AGC algorithm over a telemeter link. The same concept for determining the validity of the data is applied to this transmission as is used for tie line data. The plant requirement is always the same as the plant generation. The pulse is generated from the PRATE developed by the allocator as

$$\text{PULSLEN} = \text{PRATE} \times \text{GAINSLM}$$

where PULSLEN is the length of the pulse, PRATE is the rate allocated, and GAINSLM is the gain of the speed-level motors. The speed-level motor gain is determined emperically by ramp tests on the plant. The minimum rate used by the allocator forms the dead band of the pulse. The maximum rates are determined by a maximum pulse length. Positive pulse length is for raising the generation and negative pulse length is for lowering the generation.

Another problem with this controller is the inability to detect a no-response or slow-response condition. Before any response can be detected, the governor must be allowed to open the gates or valves. However, during this process, many pulses may be sent for which there is no response. This greatly reduces the effectiveness of the AGC system, regardless of the careful filtering and allocation used within the AGC. It should also be noted that the control is permissive since PRATE never opposes the ACE (except in ramp mode). The dispatcher must manually enter the maximum and minimum power for both normal and emergency plant operation. The dashpot bypass flag should be set any time a pulse is sent to the plant and should be cleared when no pulses have been sent for a time equivalent to the dashpot reinsertion time. Since the system is completely permissive, no ACE should be used at the plant allocator hardware located in the plant. If it is used, the "ramp" mode for the plant is totally useless.

Pulse Controller with Power Feedback (PID)

Refer to figure 28. The next level of control is the use of power feedback around the plant. The advantage is that limits may be easily sensed without waiting for the governor response. Also, some of the change of gain from water columns or boiler characteristics is eliminated. However, the response characteristics of the plant change as the various generators in the plant respond to the pulse. The plant allocator should attempt to allocate the pulse to one generator only at a time so that the gain remains essentially constant. Sudden gain changes cause the derivative terms to be large and the control is poor. Unfortunately, most hardware plant allocators do not have these characteristics.

This restriction does limit the speed of response of the plant. For the emergency assist, an emergency signal may be sent to the plant to allow all generators in the plant to respond to a pulse.

The PID algorithm does not use the speed-level motor as an integrating element for the AGC system. Instead, an integrating stage is placed ahead of the controller to convert PRATE to a plant power requirement. Thus,

$$\text{PREQ} = \text{PREQ} + \text{PRATE (TIMESLP)}$$

where PREQ is in megawatts and PRATE is in megawatts per second. The PREQ is initialized to the present plant power at mode changes and after a transmission failure is reset by the dispatcher. Another term providing frequency regulation compensation for the plant should be calculated. This term allows the governor droop to operate unhindered. The term is

$$\text{PDROOP} = \frac{\text{FAD (PPEMX)}}{\text{DROOP (60 Hz)}}.$$

Where FAD is the system frequency difference in hertz, the 60 in the denominator is the base frequency in hertz which converts the frequency deviation to per unit (pu), DROOP is the generator droop in pu frequency per pu power (usually 5 percent, or 0.05 per unit), PPEMX is the maximum plant capability in megawatts as entered by the dispatcher, and PDROOP is in megawatts. The droop is usually based on the maximum gate or full throttle which is sometimes more than the PPEMX and the droop should be adjusted to 3 or 4 percent as required. This droop compenstion should be used for all modes of plant control including basepoint and automatic modes.

The actual plant requirement then becomes

$$\text{PREQ} = \text{PREQ} + \text{PDROOP}.$$

The plant error is then

$$\text{PRATP} = \text{PREQ} - \text{PPLT} - (\text{GAINDER} \times \text{PPDER}).$$

Where PREQ is the requested power, PPLT is the actual power, GAINDER is the gain of the derivative and PPDER is the actual power derivative. The algorithm also filters the derivative. The actual plant power is the total power signal received from the plant by telemetry of PMSC signals. After these calculations, the pulse control subroutine (used for plants without power feedback) is used to provide the proper pulses.

Closed-Loop Plant Controller

Refer to figures 28 and 30. The best control that can be obtained is to close a power feedback around each separate generator with a predictor-corrector system. This allows:

1. The gain and the response time of each generator to be predicted.

2. The constraints of each generator to be detected, such as gate limit, load rejection, and separation of the plant from the rest of the system.

3. The plant operator to have a better control and oversight over the operation of the individual generators.

This type of control depends on having a powerplant generation control (PPGC) computer located at the plant. Such a computer is recommended at least for the plant that normally is used to control ACE. Examples of such controllers is given in references 3, 6, 7, and 14. These references provided indepth discussion and description of the closed-loop plant controller.

The PPGC should have the normal error detecting equipment to ensure its proper operation. Therefore, there is no need to check for slow- or no-response of the plant. The no response will be signaled by the lack of a transmission signal from the plant every 2 seconds. If a correct transmission is not received for 30 seconds, the inhibit flags are set and an alarm is generated. The signal sent to the powerplant is

$$PREQ = PREQ + PRATE.$$

There is no need for compensation with frequency because the PPGC should care for that concept. The PPGC should transmit in return the plant power, and also the number of dashpots bypassed, the maximum and minimum plant limits, and perhaps the maximum and minimum plant rates. Thus, the constraints are generated at the plant itself rather than interpreted by the dispatcher. The message formats are discussed under the subheading The Plant Communications Link.

Joint-Owned Units

Refer to figures 21 and 29. The concept of joint-owned units seems rather simple at first glance. The requirement of each owner is summed to produce the total requested generation. Then the actual generation is divided according to the percentage of the request. This concept is contrary to permissive AGC control because the joint-owned unit would be adjusted according to the unit. Also, the operating owner must be able to absorb loss of any owners request and still have control of the unit.

It is assumed that joint-owned units external to the control area will operate in the allocators like any other plant. The power and rate limits are the limits of the share of power determined by the contract. No special programming is necessary. For joint-owned units internal to the control area, the allocation of power must be treated in a special way. Limits for all owners are entered by the dispatcher and the requests from other owners are modified to fit into the available power. The allocation is then established as for any other plant, except the minimum power limit is the sum of all requests.

After the plant controllers have sent signals to the internal joint-owned unit, another special subroutine divides the output and transmits the output and limit data to the external owners.

AGC FOR THE WEST AREA

Although the "west" area for AGC is much smaller than the "east" area, and the complexity of operation is less, the preparation of a separate algorithm may require much duplication of the present algorithm without large benefits in computer memory space or execution time. The same algorithm is recommended for both systems with different tables used for each area. The additional programming would include a routine to switch between the two tables. It should be realized that a specific powerplant may be addressed by both routines. The powerplant should not ever receive control from both routines during the same period of time, but rather, the control should be able to be derived from both routines. Also, telemetered data may be used by both routines simultaneously.

If a second separate routine is desired, the elements of the present algorithm may be used. As modules are omitted, care should be exercised to ensure the initialization or calculation required for later routines is not inadvertently omitted.

ASSESSMENT OF CONTROL CAPABILITY AND QUALITY

The asssessment of control capability is important to the dispatcher so that adjustments to the allocator may be made to avoid moving all plants to their limits. The dispatcher may elect to have generators started and stopped to maintain desired margins of control. The control quality of the AGC is a more difficult concept because the definition of "good" control does not have a universal interpretation.

Margin Calculations

Refer to figures 31 and 34. To allow the dispatcher to adequately operate the AGC allocator, several margins should be calculated. The first margin is the theoretical automatic margins for increased loading and decreased loading. The margin is calculated by subtracting the PLANT REQ of each plant on automatic from either the normal upper power limit and normal lower power limit. These subtractions are then summed to give the total margin available. Plants which have a raise inhibit flag set will have the upper plant power limit set to the PLANT REQ until the inhibit flag is cleared. Likewise, if the lower inhibit flag is set, the lower plant power limit will be set to the PLANT REQ.

The second set of margins required is the base assist margins. The very same calculation, previously given, is used, except all plants on "basepoint" and "automatic" are used with normal plant limits. Plants that have the inhibit flags set are treated as previously described. The final set margins calculations is the emergency margins. The same calculation is performed except all plants not on "off" are included and the emergency limits are used rather than the normal limits. Again, plants with the inhibit set are treated as previously described.

For each of the six margins, a margin level is entered by the dispatcher. If any of the margins calculated are less than the entered margin levels, an appropriate alarm should be generated.

Other reserve calculations, such as spinning reserve or operating reserve, are not used by the AGC but are used for system security. Spinning reserve and load calculations are included in the Generation Control Format module.

System Disturbance Detector

Refer to figure 34. The detection of system disturbances outside the control area can alert the dispatcher to possible external problems that may require action if the problem is not corrected. The calculation is a prediction method and, therefore, will create occasional false alarms. However, the alerting of the dispatcher to these alarms will not be a disadvantage if the alert is not too often.

The method used is to generate an equivalent ACE of the external system using the equation

$$\mathrm{EXTACE} = -(\mathrm{PAS} - \mathrm{PS}) - 10\mathrm{B}\ (\mathrm{FA} - \mathrm{FS})$$

where PAS, PS, FA, and FS are all measured or calculated as for the normal ACE. This formula assumes all the power leaving the area is entering the external area. Likewise, the schedule for the external area is the same as for this area but reversed in sign. The contribution of the frequency bias does not reverse sign because the external area must use the frequency in the same way the local area does. If the external area is assumed to be a sister system in size, the same bias may be used as for the local system. It is immediately obvious that this assumption is not true in reality, however, the ability to use the monitored tie lines for frequency compensation is not directly associated with the external system size. Therefore, relative to the ties monitored, the frequency participation strength can be considered approximately the same as the local system.

The alarm is not generated unless the EXTACE exceeds a preset limit for either positive or negative excursions. This limit can be tied to the L_d of the local system (because the external system is assumed the same size) and could be initially set to 4 L_d.

Another problem that exists in a geographically large control area is the possibility of system isolation during a disturbance. Initially, the data from the PMSC systems will be used to detect a system breakup, however, plants that have a PPGC could transmit local frequency. If the system frequency monitored at the ECS is compared with the plant frequency, and the comparison exceeds a preset level in either direction, then an alarm would be generated indicating a possible system separation. This concept may be implemented in the future.

NAPSIC Criterion

Refer to figure 32. The NAPSIC operating manual [1] describes a minimum operating performance criterion. This criterion should be monitored with the measurements of raw (unfiltered) ACE. The measurements are to be taken over a 10-minute period and each hour of operation is divided into six 10-minute periods beginning at the start of the hour. The summary of the measurements should be logged at the end of each day. If any of the criterion is violated, the violation should be alarmed.

The zero crossings of raw ACE should be counted and added for each 10-minute period. Also, the maximum time between zero crossings within the 10-minute period should be recorded along with the time at the start of the maximum zero crossing. If a zero crossing does not occur within 10 minutes, an alarm should be generated.

The raw ACE should be summed for each full 10-minute period and the average calculated as

$$\text{AVERAGE} = \frac{\Sigma\,(\text{ACEA} \times \text{TIMESLP})}{600 \text{ seconds}}.$$

The summation should be restarted at the beginning of each 10-minute period. If the AVERAGE exceeds L_d, an alarm should be sounded.

The maximum and minimum deviation of ACE must be determined for each 10-minute period. The number of times the absolute value of ACE exceeds 3 L_d should be determined for each 10-minute period. When the maximum ACE exceeds 3 L_d, the length of time until the ACE returns to 90 percent (or other adjustable value) of the maximum should be recorded in the 10-minute period when the return occurred. This will provide information for the 1-minute response to a disturbance.

Standard Deviations

Refer to figure 33. Another way of determining the "goodness" of AGC control is to examine the standard deviations of selected quantities [9,10,11]. Because this is not a NAPSIC requirement, these measurements need not be made except at the request of an engineer and the time period of the averages should also be entered by the engineer. The data should be logged at the end of the time period on the engineering programming console to allow hard copy to be made if desired. All integral summations should be zero at the start of the period desired. The first quantity is

$$\text{SIGACEA} = \sqrt{\frac{1}{\text{TT}} \int_0^{\text{TT}} (\text{ACEA})^2 dt}$$

where SIGACEA is the standard deviation of ACE and ACEA is unfiltered ACE. The integration may be done in rectangular form as

$$SIGACEA = \sqrt{\frac{\sum_{i=1}^{N} (ACEA)^2}{N-1}}$$

where N is the number of 2-second intervals (or number of executions of the AGC). The maximum time limit will be 2 days for the calculation of a standard deviation. Other standard deviations are:

$$SIGACEB = \sqrt{\frac{\sum_{i=1}^{N} (ACEB)^2}{N-1}}$$

$$SIGACEP = \sqrt{\frac{\sum_{i=1}^{N} (ACEP)^2}{N-1}}$$

$$SIGFREQ = \sqrt{\frac{\sum_{i=1}^{N} (FS\text{-}FA)^2}{N-1}}$$

$$SIGINT = \sqrt{\frac{\sum_{i=1}^{N} (PS - PAS)^2}{N-1}}$$

$$SIGGEN = \sqrt{\frac{\sum_{i=1}^{N} (\Sigma\ PREQ\text{-}\Sigma\ PPLT)^2}{N-1}}$$

and

$$SIGGENR = \sqrt{\frac{\sum_{i=1}^{N} (\Sigma\ PPDER)^2}{N-1}} .$$

Another standard deviation which is useful is the filtered interchange deviation where

$$INTFIL = (1 - e^{-T/\tau})(PS - PAS) + INTFIL\,(e^{-T/\tau})$$

where T is the sampling period in seconds (2 seconds) and τ is the filter time constant in seconds (600 seconds). The filter should be initialized to zero. Then the standard deviation is

$$SIGINTFIL = \sqrt{\frac{\sum_{i=1}^{N} (INTFIL)^2}{N-1}} .$$

Several integrals should be available over the same period as the standard deviations. These integrals should be initialized to zero at the start of the period. If the integral overflows, the error should be noted in the log of the data. The integrals are:

$$IISPEC = KII \sum_{i=1}^{N} (PAS - PS)$$

where KII is 1/1800 if N is 2-second intervals and IISPEC is in megawatt hours.

$$IACESPEC = KIA \sum_{i=1}^{N} (ACEA)$$

where KIA is also 1/1800 and the IACESPEC is in megawatt hours, and

$$MUTUALAID = KMA \sum_{i=1}^{N} (FA - FS)\,(PAS - PS)$$

where KMA is one over the reference frequency in hertz and the number of seconds per hour or

$$\text{KMA} = \frac{T}{60\,(3600)}$$

and MUTUALAID is in magawatt hours. The mutual aid helps determine the mutual benefit between control areas; as the MUTUALAID takes a negative direction, responsible control is indicated. If the MUTUALAID takes a positive direction, irresponsible control is indicated. A positive MUTUALAID shows the external control areas are helping the local control area. For smaller systems, the square root may be omitted and the square of the standard deviation may be displayed.

These quantities should be recorded during various operating conditions and used as comparisons when filter constants, plant controller constants, or allocator constants are changed. Also, some of the charts from operations using the analog control equipment with some of the standard deviations and integrals manually calculated may be valuable in this comparison process.

The definitions of the various variables used in the previous equations are as follows:

ACEA	Raw ACE in megawatts.
ACEB	Filtered ACE in megawatts.
ACEP	ACE from the probability filter in megawatts.
FA	Actual frequency in hertz.
FS	Scheduled frequency in hertz.
i	Index of summation.
IACESPEC	The special integral of raw ACE in megawatt hours.
IISPEC	The special inadvertent interchange in megawatt hours.
INTFIL	Filtered interchange in megawatts.
KIA	Constant for the IACESPEC summation.
KII	Constant for the IISPEC summation.
KMA	Constant for MUTUALAID calculation.

MUTUALAID	The mutual aid in magawatt hours.
N	The number of executions of the AGC algorithm over the period TT.
PAS	The summation of actual interchange power.
PPDER	The actual power plant derivative for each plant not in "off" mode in megawatts per second.
PPLT	The actual power plant total generation of each plant not in "off" mode in megawatts.
PREQ	Powerplant requirement of each plant not in "off" mode in megawatts.
PS	The interchange schedule in megawatts.
SIGACEA	The standard deviation of raw ACE in megawatts.
SIGACEB	The standard deviation of filtered ACE in megawatts.
SIGACEP	The standard deviation of probability-filtered ACE in megawatts.
SIGFREQ	The standard deviation of frequency deviation in hertz.
SIGGEN	The standard deviation of the total generation of the powerplants in megawatts.
SIGGENR	The standard deviation of the rate of change of generation in megawatts per second.
SIGINTFIL	The standard deviation of the filtered net interchange error in megawatts.
T	The average time period between AGC program executions in seconds.
t	Time in seconds.
TT	The total time interval in seconds.
τ	Time constant in seconds.

Frequency Domain Analysis

Refer to figure 33. The previously mentioned standard deviations are valuable in determining control "goodness." However, the deviations are monitoring all the action of the control system. Some of the higher frequency action is not controllable nor should control be attempted. Therefore, a measurement of these standard deviations using data filtered for various control frequencies to eliminate the higher frequency action may demonstrate the control "goodness" more accurately. Furthermore, the measurements would show that the higher frequencies are not controllable as desired.

There are several possibilities in developing this data. The concept of Fast Fourier Transforms would be useful but the size of the data block is limited and not easily varied. Another method is to implement several bandpass filters to sort the raw data into several frequency zones. Bandpass filters with wide bandwidths and without sharp peaks would sort the information sufficiently.

A suggested filtering system can be used that approximates the various bandpass filters without the excessive calculation of bandpass filters algorithms. This system creates three simple filters to create data for frequencies above three specific cutoffs. The raw data is filtered as

$$\text{FILTERDATA} = (1 - e^{-T/\tau})\,\text{RAWDATA} + (e^{-T/\tau})\,\text{FILTERDATA}$$

The filtered data will use T as 2 seconds, and will always be initialized to zero. The three τ values may be set as desired by the engineer but initially will be 60, 180, and 300 seconds. Quantities calculated or measured elsewhere in the algorithm should be filtered for each of the three time constants. The standard deviations of the output of each filter and for raw data are calculated as:

$$\text{SIGDATA} = \sqrt{\frac{\sum_{i=1}^{N}(\text{FILTERDATA})^2}{N-1}}$$

$$\text{SIGRAWD} = \sqrt{\frac{\sum_{i=1}^{N}(\text{RAWDATA})^2}{N-1}}$$

The standard deviations for the very slow signals can then be calculated as

$$\text{SIGVSLOW} = \sqrt{(\text{SIGRAWD})^2 - (\text{SIGDATA}_{\tau=300})^2}$$

The result is an approximation but will provide useful comparative measurements. Continuing with the remaining time constants:

$$\mathrm{SIGSLOW} = \sqrt{(\mathrm{SIGDATA}_{T=300})^2 - (\mathrm{SIGDATA}_{T=180})^2}$$
$$\mathrm{SIGMED} = \sqrt{(\mathrm{SIGDATA}_{T=180})^2 - (\mathrm{SIGDATA}_{T=60})^2}$$

and

$$\mathrm{SIGFAST} = \mathrm{SIGDATA}_{T=60}.$$

Using these intermediate standard deviations, the effects of changing gains or time constants on the filters that modify the actual ACE, or the effects of modifying the allocator or generator controller can be compared.

The standard deviations calculated should be:

1. raw ACE, ACEA
2. filtered ACE, ACEB
3. probability-filtered ACE, ACEP
4. interchange error, PS − PAS
5. generation error, Σ PREQ − Σ PPLT (plants not in "off")
6. generation rate error, Σ PPDER (plants not in "off")

Perturbation and Response Analysis

Refer to figures 5 and 23. Determining if the control is performing correctly is always desirable in any control system. In an AGC system, the normal operation of the system usually cannot conclusively demonstrate the correctness of control. Therefore, a method of forcing the control to respond to a prescribed disturbance is necessary. The disturbance best suited to AGC is the ramp since it is most like the normal method of operation. The "ramp" mode provided for the generators allows a single plant to be observed during a prescribed ramp while the remaining plants in the control area can counterramp without large disturbances in ACE.

A ramp disturbance for the entire AGC system requires that inadvertent interchange or time error must accumulate. To minimize this error, a ramp must first increase from zero to a positive maximum, then reverse with the same rate to a minimum, and then at the same rate, return to zero. The completion of the entire test in 8 minutes would be satisfactory, and the maximum schedule should be about L_d. The ramp must be used on the total power schedule; also remember that the neighboring AGC areas will fight the change. The use of the test ramp, the start time, its rate, and its maximum power level should be entered by the engineer. The desired variables should be monitored on strip chart recorders.

COMPUTER REQUIREMENTS

Because specific hardware and operating system requirements have not been chosen, the constraints that the algorithm place on the hardware and the operating system must be discussed. Relationships to memory size, speed of execution, and data base size are directly related to programming techniques and language structures. The guidelines are discussed in the following paragraphs.

Timing Constraints

Refer to figure 2. Because of the rectangular integration and differentiation algorithms used for most of the digital filters, the AGC algorithm should operate at 2-second intervals as much as possible. The interval may be as short as 1.0 second or as long as 3.0 seconds. The intervals between algorithm calls must have no worse than a normal distribution (Gaussian Distribution) centered at 2 seconds with a standard deviation of 0.33 second. The optimum condition is to have a standard deviation of zero. The absolute minimum interval between algorithm passes should not be less than 1 second because of the problems in calculating derivatives. The absolute maximum time between passes is 6 seconds when the remaining functions of the computer are in an emergency overload condition. This must not occur more than five times a day because the algorithm may become unstable depending on the power system configuration.

The choice of 2-second execution time is based on an important control philosophy. Most digital control system designers have found that the Nyquist frequency for a specific system should be at least 10 times faster than the frequency at phase or gain margin crossovers. In actual AGC systems and specifically, in the North and South Dakota areas, increase in gains usually result in a crossover frequency between 1 and 1.5 cycles per minute. For 1.5 cycles per minute, the Nyquist frequency should be 15 cycles per minute, and the number of samples per minute should be 30. The 2 seconds per sample ensures good phase and gain control of a 1.5-cycle-per-minute frequency component.

Analog Inputs

Refer to figure 6. The algorithm requires that all inputs of tie line power, frequency, time, dynamic schedules, MAPP inputs, and plant power be sampled previous to the execution of the algorithm. Although a 4-second transport lag can exist as described in the Tie Line Power subsection, the data must never be dormant (i.e., continue without an update) when the algorithm actually uses the data. If the data are monitored asynchronous to the algorithm, the algorithm not be executed unless the data have been sampled after the start of the previous AGC algorithm execution.

The data should contain no more than a 0.5-percent error at rated transducer output and should not exceed more than 1 percent of the actual value for any reading. The exceptions are the frequency and time which have been discussed in previous sections, Frequency Bias and Time Error and Sensitivity. This accuracy must include the accumulated errors in the transducer, the sampler, the analog-to-digital converter, any round-off error in the various algorithms, and any communication errors. Thus, the data stored in the data base used by the algorithm must have this accuracy compared to the actual quantity in the primary monitoring circuits of the power system. The data should have between 1 and 3 seconds of simple analog filtering to avoid aliasing [13].

PMSC systems, PPGC systems, or any other computer-to-computer link must be treated the same as analog data. The data must not be dormant and must have the required accuracy. The MAPP computer is an exception because data will not be required on a regular basis.

Plant Communication Link

Refer to figures 13, 19, and 20. Communications with the PPGC computers should be implemented in an ASCII format on a 1200-baud communications link. The message should contain:

1. An SOH (start of header) symbol
2. A data identifier
3. The data defined by the data identifier
4. A checksum identifier
5. The checksum
6. An EOT (end of transmission) symbol.

Items 2 and 3 may be repeated as often as necessary to send all the data required. The total time for transmission to the PPGC and the response from the PPGC should not be more than 2 seconds. The identifiers may be any capital or lowercase letter, or a pair of any capital or lowercase letters. The data should be in numbers with the "minus" and "period" being the only symbols. The identifiers are assigned as follows for data to the PPGC.

1. "B," the status identifier. The number following means: (a.) 1 - control is available to use or is in use (b.) 0 - control is not available. This must be transmitted every 2 seconds.

2. "C," the plant requirement identifier. The number following from one to four digits is the plant power requirement in whole megawatts. This must be transmitted every 2 seconds.

3. "Dn," the plant schedule identifier where n is a letter describing the time location of the schedule. The schedule is from one to four digits indicating plant power in whole megawatts. Negative power is not used. The letters substituted for n are:

   a. "a" through "x" means the hours 0 through 23 respectively.
   b. "y" means the extra hour in the daylight savings time change.
   c. "A" means the present hour.

d. ''B'' means the next hour.

The plant schedule is transmitted only as needed. If the PPGC does not use schedules, this information need not be transmitted.

4. ''E,'' the emergency assist identifier. A one (1) transmitted after the E indicates an emergency assist is in progress. A zero (0) transmitted after the E indicates no emergency assist procedures are being used. This is used by the plant algorithm as described previously and is optional.

The identifiers for the data from the PPGC are assigned as follows:

1. ''P,'' the status identifier. This must be transmitted every 2 seconds. The number following means:

   a. ''0'' - PPGC not controlling generators (''off'' mode).

   b. ''1'' - plant operator controlling generators through the PPGC (''plt'' mode).

   c. ''2'' - the ECS computer controlling generation with the plant requirement (''pscc'' mode).

   d. ''3'' - Stop allocation up or the powerplant controller algorithm should set the inhibit-up flag (''stu'' mode).

   e. ''4'' - Stop allocation down or the powerplant controller algorithm should set the inhibit-down flag (''std'' mode).

2. ''Q,'' the total plant power identifier transmitted every 2 seconds. The number following from one to four digits is the total net plant power in whole megawatts.

3. "Rn," the maximum values identifier. These may be transmitted as needed. The data following is one to four digits indicating the power in whole megawatts. The "n" may have the following letters substituted:

a. "a" means the maximum normal plant power limit.

b. "b" means the maximum emergency plant power limit.

c. "c" means the minimum normal plant power limit.

d. "d" means the minimum emergency plant power limit.

4. "Sn," the maximum rate identifier. These may be transmitted as needed. The data following is one to three digits indicating the rate of power change in whole megawatts per minute. Negative rates are not used. The "n" may have the following letters substituted:

a. "a" means maximum normal loading rate.

b. "b" means maximum emergency loading rate.

c. "c" means maximum normal unloading rate.

d. "d" means maximum emergency unloading rate.

e. "e" means minimum rate for the plant.

5. "T," the dashpot bypass identifier. The number following is the number of dashpots that are bypassed in the plant.

6. "Un," the individual unit power identifier. The letter following indicates the generator number and the number following is the number of megawatts to the nearest whole megawatt

with sign. The "n" may be "a" for generator 1, "b" for genrator 2, etc. This data is not used by the AGC algorithm directly but may be used in ECS displays.

7. "Vn," the individual unit status indentifier. The letter following indicates the generator number and the number following indicates the status. The "n" may be "a" for generator 1, "b" for generator 2, etc. The numbers following the "n" mean:

a. "0" - generator off line and unavailable.

b. "1" - generator off line and available.

c. "2" - generator on and running.

d. "3" - generator on and condensing.

This data is not used by the AGC algorithm directly but may be used in ECS displays.

8. "Wmn," the individual unit limit identifier. The first letter following indicates the generator number, the second letter following indicates the type of limit and the number following the two lower case letters is the limit in whole megawatts with a sign if negative. The "m" may be "a" for generator 1, "b" for generator 2, etc. The letters substituted for "n" are as follows:

a. "a" means maximum normal generator power.

b. "b" means maximum emergency generator power.

c. "c" means minimum normal generator power.

d. "d" means minimum emergency generator power.

The data are not used by the AGC algorithm directly but may be used by other ECS functions. These generator quantities are sent along with plant totals. It is not necessary that these totals match with plant totals since station service or other power may not be accounted for. The information should be sent every 2 seconds when the plant is on AGC control.

The transmission is half-duplex in nature. The PPGC acts as a slave and ECS acts as the master. The PPGC need never respond with a message unless a valid message is received from the ECS. The PPGC should respond within 1.5 seconds of the receipt of the ECS message. If a valid message is not received from the PPGC, the normal failure detection system described in the Intertie Power Measurements section should be used. The minimum message is the "control not available" from the ECS and a return of "plant status" and "total net plant power" from the PPGC.

The checksum consists of an exclusive "OR" function on the 7-bit ASCII codes from and including the SOH through the Z. Even parity is attached to all ASCII characters as the eighth bit, including the checksum. If the calculated checksum does not match with the transmitted checksum, or if a parity error is detected, the message is not considered valid.

The MAPP communications is not yet defined but it will probably take the same form.

Plant Pulse System

Refer to figure 28. The pulses from the AGC plant controllers for plants not having PPGC systems are telemetered to the plant as a raise signal or a lower signal. The relays at the plant must respond to the signal within 0.5 second after the transmission is initiated at the ECS. The timing of the relays will be to the closest 0.1 second. The maximum pulse length is 1.8 seconds allowing 0.2 second of no pulse. This allows the plant allocators to function properly. If the plant allocator does not need the dead time, then the pulse may be as long as desired. However, the pulse length from a previous pass of the AGC algorithm must not be added to the pulse length of the next pass. This "integration" may cause instability in the rate feedback controller. The overall pulse time accuracy should have an error of less than 0.05 second for any pulse length measured at the output of the plant relays.

Permanent Strip Chart Outputs

Refer to figure 35. The most visible and easily understood display system for the dispatcher consists of large, wall-mounted strip chart recorders running 25 to 150 mm/h (1 to 6 in/h) (adjustable on the chart), with two pens per chart. Analog outputs to drive at least 32 pens should be provided so that 16 large charts may be used. The assignment of 24 pens (12 recorders) should be made by the engineer using the calibration system for constants. The remaining eight pens (4 recorders) should be available for the dispatcher to assign to any tie line power, schedule, dynamic schedule, frequency, raw ACE, generator power, generator reference, or load calculation. Also, summation of tie line powers forming certain important area net interchanges should be available.

Engineering Evaluation Ouputs and Inputs

Refer to figures 35 and 36. An extremely valuable tool for the engineer in evaluating and "tuning" an AGC control system are strip chart recordings using a general purpose strip chart recorder with speeds of millimeters per minute, as well as millimeters per second. Provision should be made for 8 channels of plus or minus 10-volt outputs and 2 channels of relay outputs. These outputs should be available near the engineering or programming console so the engineer may connect the recorder of his choice. The outputs should allow the engineer to select any one of the variables in the AGC algorithm or any of the inhibit or alarm flags. Also, the engineer must be able to change the relationship scale of the variable to the output voltage, and also include an offset added to the variable. A mask should be included for alarm and inhibit flags.

Eight analog inputs for a plus or minus 10-volt signal generator should be provided. Two logic inputs should be provided.

These inputs and outputs should have the capability of operating simultaneously on any channel and should have multipliers, dividers, and offset for the input; separate offset, multipliers, and dividers for the output; simultaneous display of the output and input; and the ability to enter an input using the keyboard when the analog signal is not being driven by a signal generator. The logic inputs and outputs should be treated the same except a mask should be used. Any data should be available for display in integer, floating point, or octal (or hexidecimal) formats.

Addresses should be in octal (or hexidecimal) and should include a bias for the program or table, and an offset into the program or table as found in the program listings. The data must be updated at least as often as the AGC algorithm runs and preferably, the priority for calibration should be higher than the AGC algorithm priority.

There should be a separate calibration system for AGC constants to allow at least 10 constants to be changed or displayed simultaneously. This format should be similar to the variable calibration, previously described, for ease of operation, except the analog inputs and outputs would not be present. The constants would be read on demand and continuous scanning would not be required. The format should allow the constants to be simultaneously entered into the program, if desired. Disc update is automatic within the AGC algorithm. The format should allow multiplication, division, offset, and masking of all data. Also, the data should be available in integer, floating point, and octal (or hexidecimal). Addressing should include bias and offset.

A third calibration system may be provided to care for other programs than the AGC algorithm.

Spare ASCII Ports

Refer to figure 36. An extremely valuable tool in debugging data from the ASCII ports is to allow manual entry and display of any ASCII port data using a spare ASCII port with a variable baud rate, full or half duplex, and selectable parity. The calibration format should be used to allow at least five data values to be entered, each after the identifiers P, Q, R, S, and T. The data should be capable of being stored into any place in the input data tables and the corresponding fail flag set. No parity or checksum checks should be required and carriage returns and line feeds should be ignored. Another five data values should be capable of being output in a message with the identifiers A, B, C, D, and E. No checksum should be generated, no parity used, and the EOT character should be followed by a carriage return and line feed. This would allow a normal CRT terminal to simulate an ASCII link.

DISPLAY REQUIREMENTS

The display requirements are provided as a minimum requirement for use with the algorithm. There is no attempt to completely define the display as many hardware and software factors play a part in the generation of displays.

Buffers

Refer to figures 3 and 36. The algorithm must not have the data used during the execution changed by any source until the algorithm is complete. It is possible through careful evaluation of the variables and constants within the algorithm to "turn off" any other software and hardware system that may change the variable or constant until the algorithm is finished with the variable or constant. This has the advantage of reducing buffer sizes but creates problems when the programs are later modified to accommodate changes in the power system or AGC concepts.

A more acceptable method is to set flags indicating new data are available so that it may be introduced at the proper place in the algorithm. The description of the typical buffer transfer is shown on flow charts, Typical Data Transfter Techniques; all transfers use these techniques.

Transfers of data into the AGC algorithm from external programs rely on a flag and a time. Within the flow charts, each flag is designated by FLAG followed by two or three identifying letters. The associated time is TIME followed by the same identifying letters. The flag must be cleared by an executive program before the AGC algorithm runs. The external program sets the flag when the data are ready for transfer and are cleared by the AGC algorithm after transfer is complete. The time is set by the external program when the flag is set. The time allows the data to be transferred at a future time so that schedule changes, mode changes, etc. can be preset to execute at the beginning of the hour or when desired. Normally, schedules will be set only 1 or 2 hours in advance. The time variable allows transfers to be scheduled 23 hours and 29 minutes ahead. The 30 minutes test allows the time which is passed (normally only 1 or 2 seconds) to be executed immediately, and 30 minutes are allowed to give maximum flexibility. The data to be transferred are used by the program within 2 seconds of the set time. The program can begin execution without transfers by using the power-up initialized values of the data. If constants are transferred (as opposed to schedules, modes, etc.), the initialized value is updated so that the new constant will be used on the next power-up.

Transfers out of the AGC algorithm are the same as transfers in, except time is not used. All data from the AGC algorithm may be used immediately when the flag is set. The external program should clear the flag when the data are transferred. Often, the AGC algorithm does not check the flag before setting the flag because the algorithm may not require that the data be used, and is producing the data for the convenience of other programs.

Alarms are also handled in a buffer concept. The alarm buffers are cleared at power-up. A temporary alarm buffer is cleared at the start of each AGC algorithm execution and each alarm is set as needed. At the end of the algorithm, the alarms are transferred to the actual alarm buffer using timers. Each alarm may be adjusted using the alarm constants to remain clear until time passes with the alarm set, or the alarm may be blocked so that it cannot repeat in less than a set time.

Control Formats

Refer to figures 34 and 37. The formats for allowing the dispatcher to monitor and control the AGC algorithm are as important as the algorithm itself. Studies have shown [15,16] that the dispatcher must be able to observe changes from his entries and from power system data input within a maximum of 4 seconds after the dispatcher entry or after the data have been sampled at the actual source. Otherwise, the dispatcher will assume the computer is slow, and his decision process is interrupted. Because the data are sampled on a 2-second period, the maximum "age" of the data from the action on the power system to the display observed by the dispatcher is 6 seconds. This includes all sampling, communication links, and software manipulation to present the data to the dispatcher.

The required formats include:

1. East AGC signal flow (2 pages).
2. West AGC signal flow (2 pages).
3. System data monitor (several pages) including tie line power, dynamic schedules, and frequency.
4. Plant data monitor (several pages).
5. Schedule entry and generation scheduling (used by the Power and Energy Scheduling and Generator Scheduling programs).

These formats do not replace any other control or summary format, but are in addition to the other formats that may be specified. Formats for the engineer must include:

- Calibration and data change format for use with the eight-channel recorder, signal generator, and ASCII parts.

- NAPSIC and standard deviation summary formats.

- Constants entry formats similar to calibration.

These formats have rather complicated interaction procedures and it is recommended that a conversational mode of data entry be used. The use of the light pen at a given poke point should provide a control or entry tree at the bottom of the display. The control trees may be used to call new control trees as the sequence progresses but some method must be provided to remind the dispatcher of the previous control trees so that the location in the control sequence is always known.

The formats should use line diagrams similar to single line diagrams to indicate the "flow" of control paths. Colors of the lines should indicate the modes of the various control elements. Changes in the flow of control should be initiated by addressing special "breaker" symbols on the flow diagram. Pertinent data should be displayed with minimum explanation and the flow diagram should be used to interpret the data as in switchyard single-line diagrams. Formats must be designed with much interaction of the dispatchers as well as the engineers. A sample of a data preparation module is included in the algorithm as well as the format description. This is only a suggestion and modifications should be made to suit. Also, a suggested format for AGC signal flow is given with no sample module supplied. Formats are not trivial in size of computer memory or processing time; great effort should be made to reduce the necessary data shown on the formats.

INITIALIZATION

The initialization and testing of the AGC algorithm provides many challenges. The initialization divides into two categories, the initialization of the algorithm for mode changes and the initialization of all the constants used by the algorithm.

Initialization of the Algorithm

When the algorithm is first executed by executive software, the initialization will be referred to as "power-up" or cold start. The data in the memory is not good and the memory must be refreshed or reloaded with tables from a nonvolatile storage. The mode of the AGC will be "suspend" where all quantities are active and monitoring but the plant controllers do not function. All plant requirements are continually set equal to the plant's actual generation and no pulses are sent to the plant. For the first pass, all values required from the previous pass will have present pass values substituted so that all filters will be initialized.

A "warm" start assumes that the data in the memory are good and that no refresh or reload is needed. Even if the algorithm is interrupted in the middle of execution and restarted within 6 seconds, no initialization is required. If the algorithm is not executed for more than 6 seconds for any reason, a complete power-up initialization should take place and the AGC should be in the "suspend" mode. An alarm should be generated indicating the AGC is suspended.

The ''mode-shift'' initialization should be done if any of the AGC control paths are changed during normal operation. This includes changing plant modes, allocator modes, filters for the ACE, the method of generating the ACE, or the change of a tie line mode. Each mode initialization should strive to minimize the disturbance and, as far as practical, the previous modes should continually provide initialization for the next mode.

Initialization of Constants

Refer to figures 3 and 36. During the final stages of software development of the algorithm, all constants required for the algorithm should be provided. Also, all initial values of all plant limits and other dispatcher entries should be provided. In this manner, the software development engineeer need not make decisions on constants by default. As the dispatcher or engineer enters new constants or plant limits, the value should be properly stored in the mass storage media. If a power-up initialization or ''cold'' start occurs which uses the nonvolatile storage media as a source, the algorithm will function with the latest constants. The disc update concept used throughout the AGC algorithm will provide this feature.

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APPENDIX

(Constants used in flow diagram of fig. 1.)

System	
T_M	Mechanical time constant
D	System damping
K_X	Synchronizing coefficient
Plant	
K_{SL}	Speed level motor gain
T_g	Governor servo gain time (s)
σ	Droop
δ	Temporary droop
T_r	Recovery time (s)
K_H	Hydraulic gain
T_W	Water starting time (s)
PPGC	
T_G	Equivalent governor time constant (s)
AGC Algorithm	
B	Frequency bias (MW/0.1 Hz)
K_T	Time error sensitivity (MW/s)
K_M	MAPP power bias coefficient
K_{II}	Inadvertant interchange coefficient (1/h)
T_s	AGC system response time constant (1/s)
T_D	Digital smoothing time constant
K_{ACE}	ACE gain
K_P	Pulse generator gain
K_D	Power derivative gain
General	
S	LaPlace complex frequency
Z^{-1}	One delay period of sampling

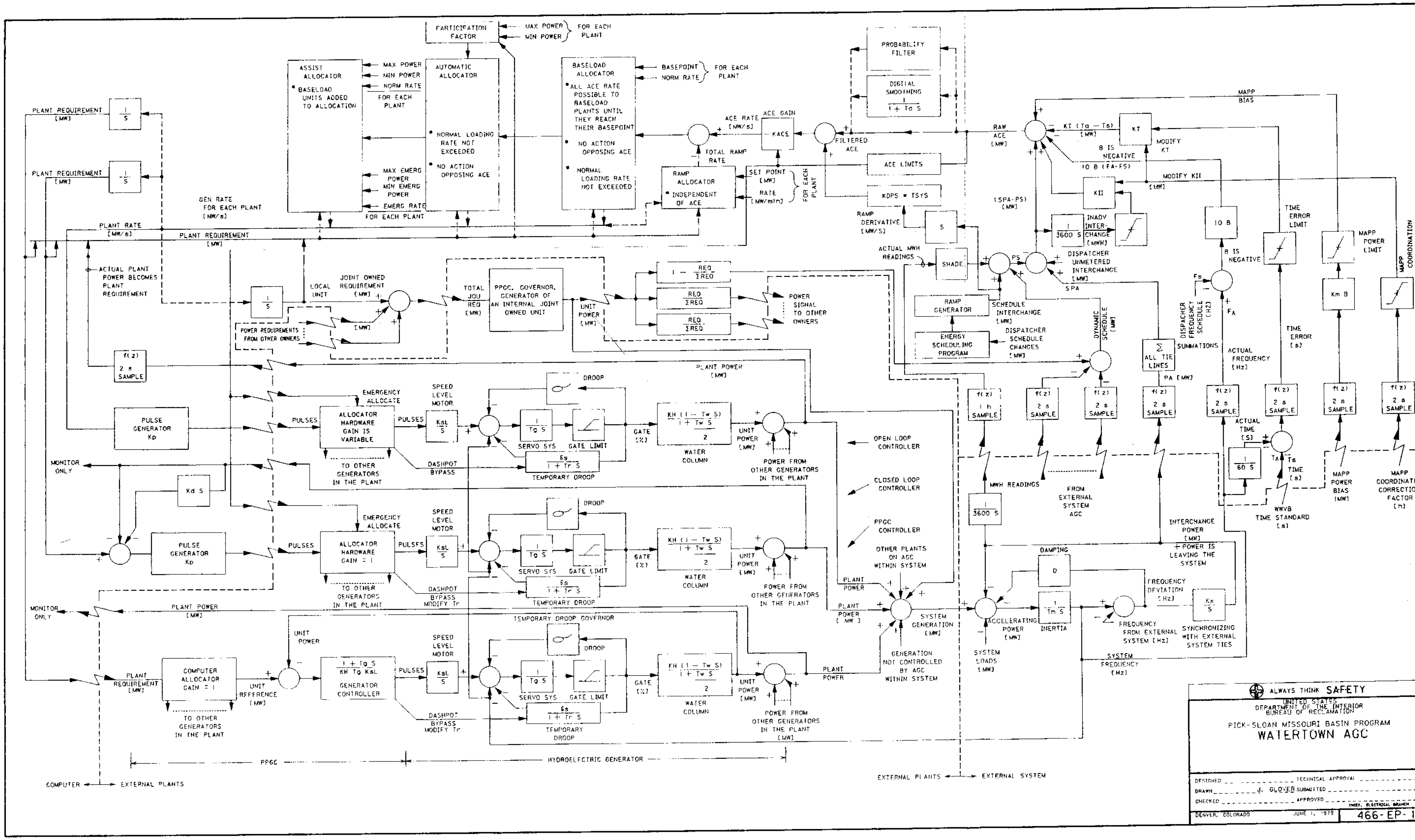


Figure 1.—Watertown AGC signal flow diagram.

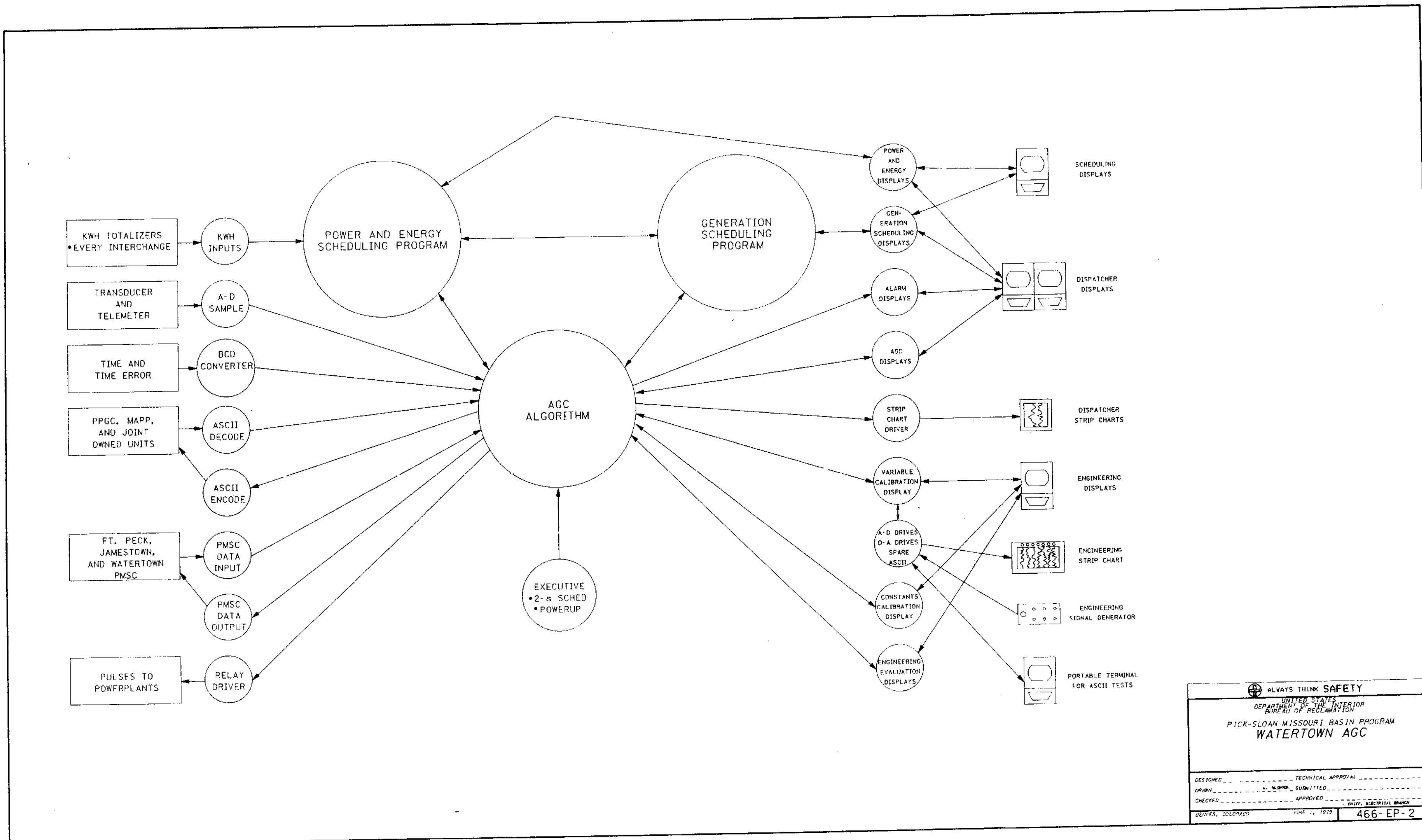


Figure 2.—AGC algorithm (Sheet 1 of 2).

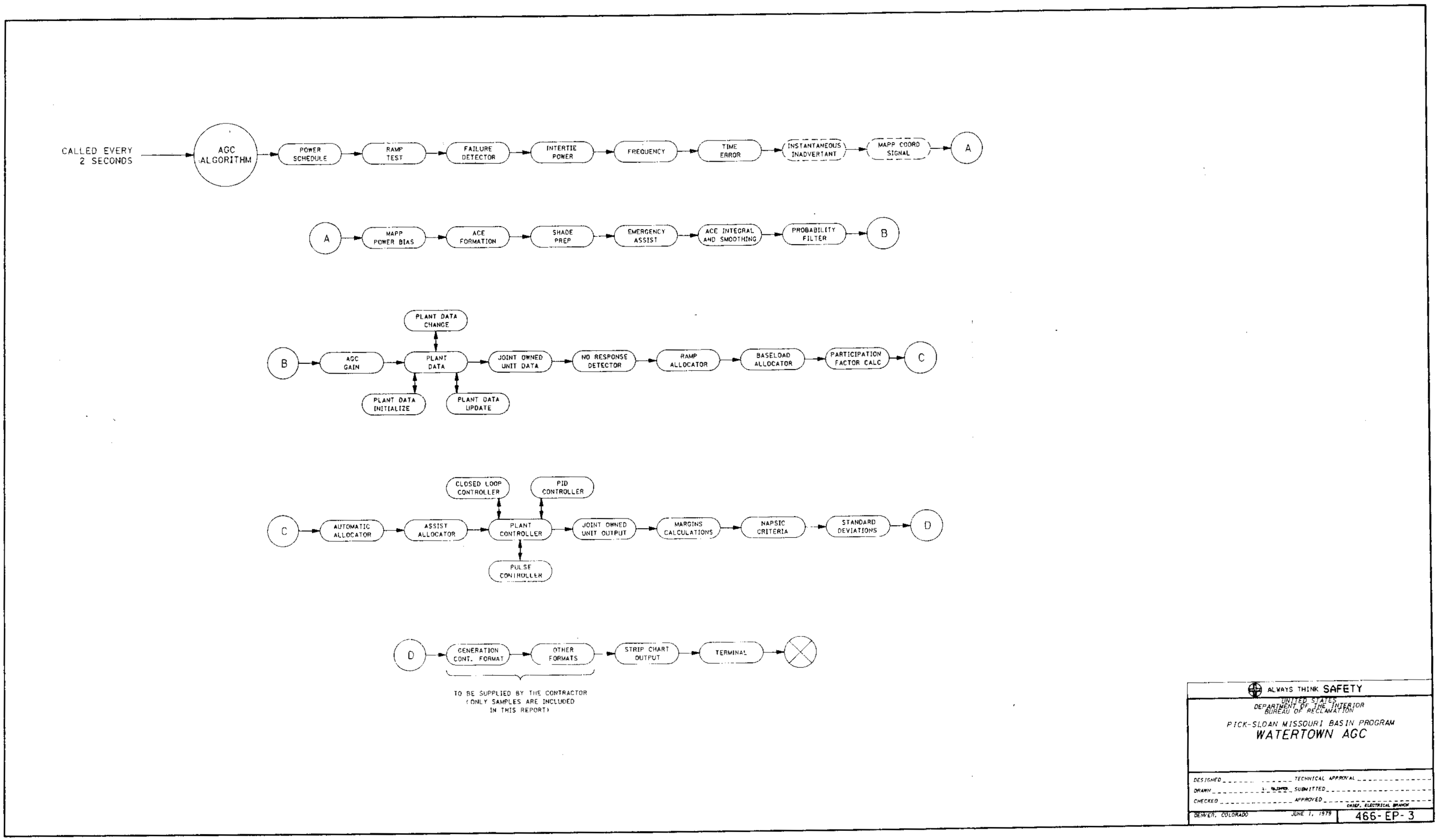


Figure 2.—AGC algorithm (Sheet 2 of 2).

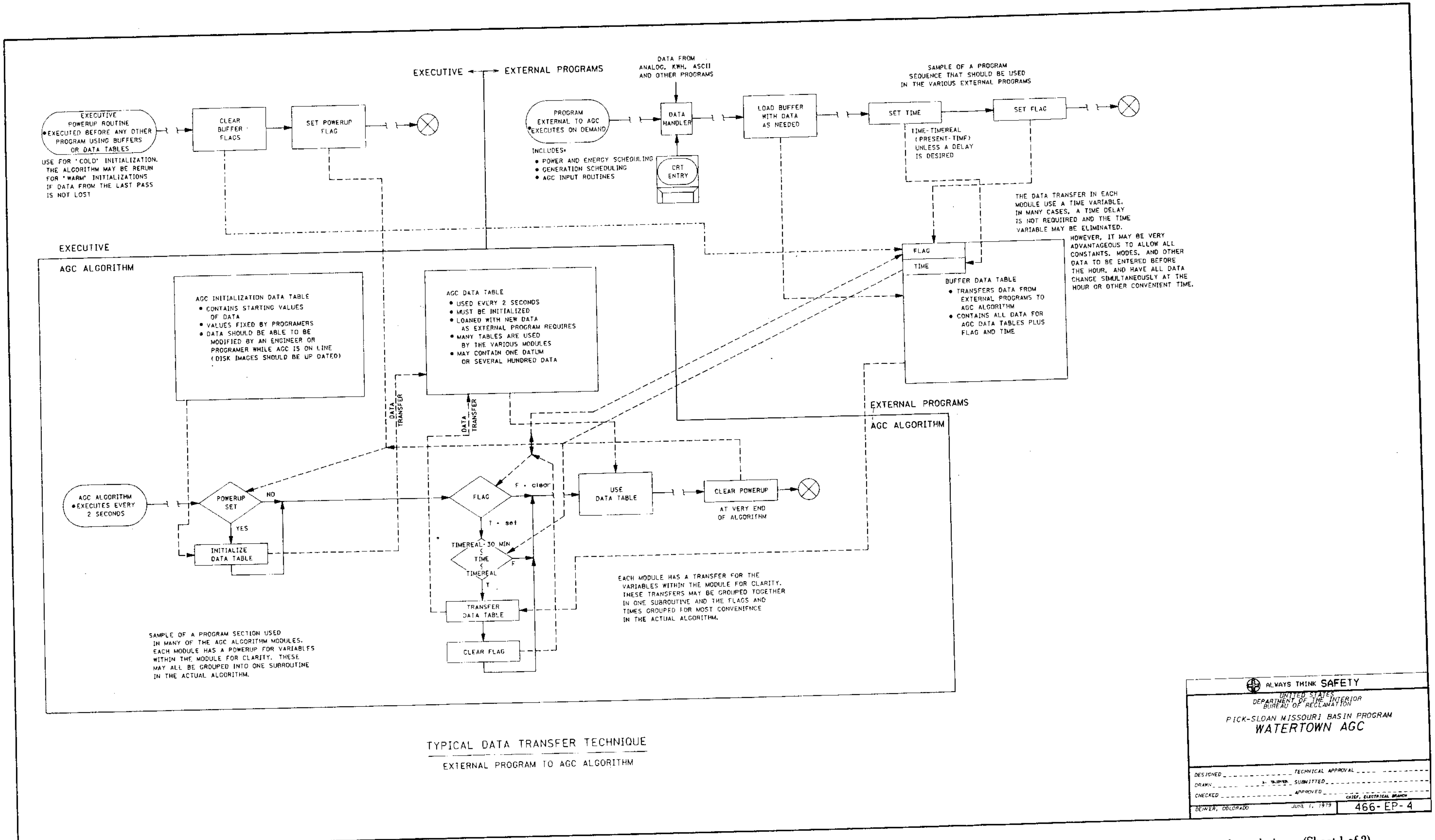


Figure 3.—Typical data transfer techniques (Sheet 1 of 2).

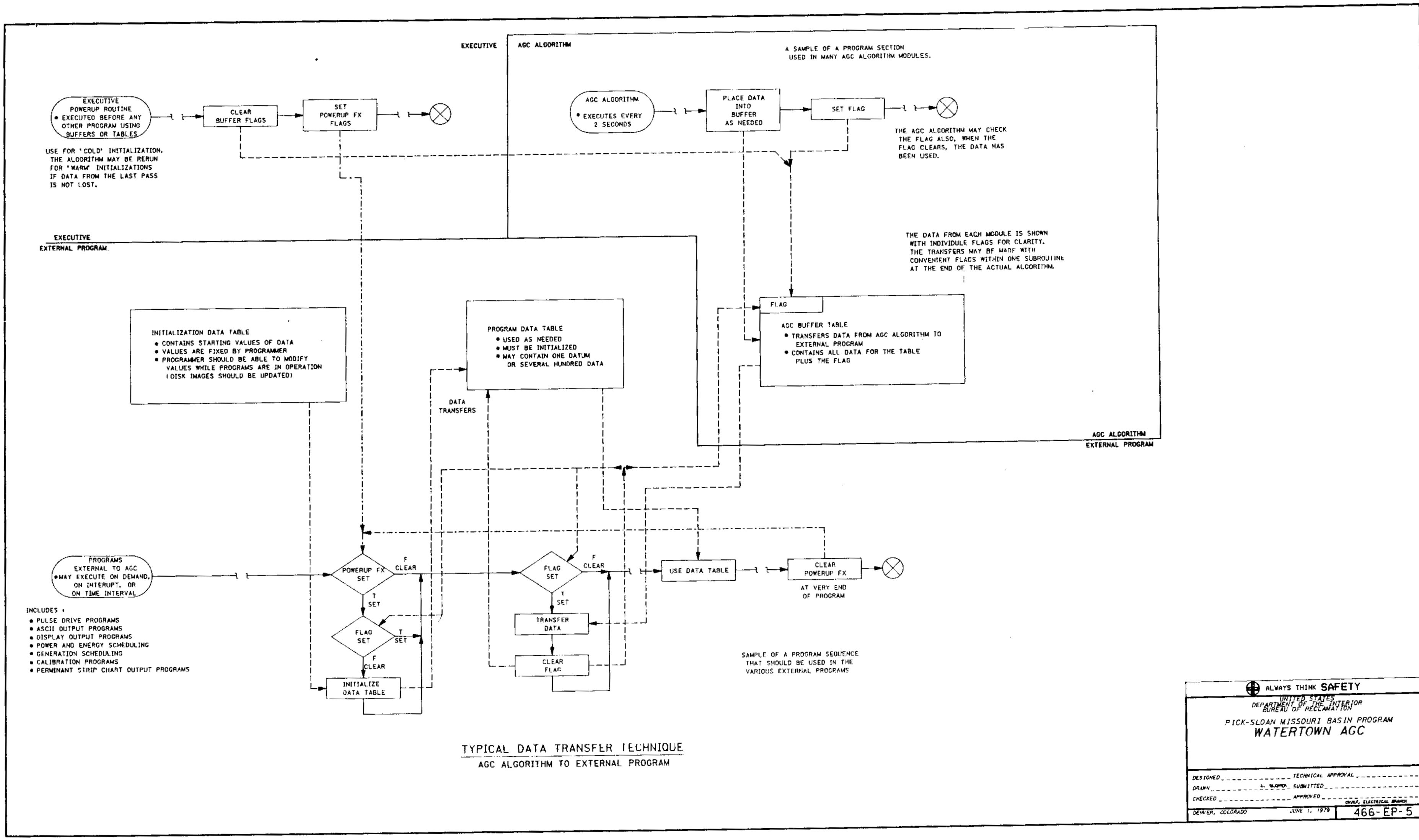


Figure 3.—Typical data transfer techniques (Sheet 2 of 2).

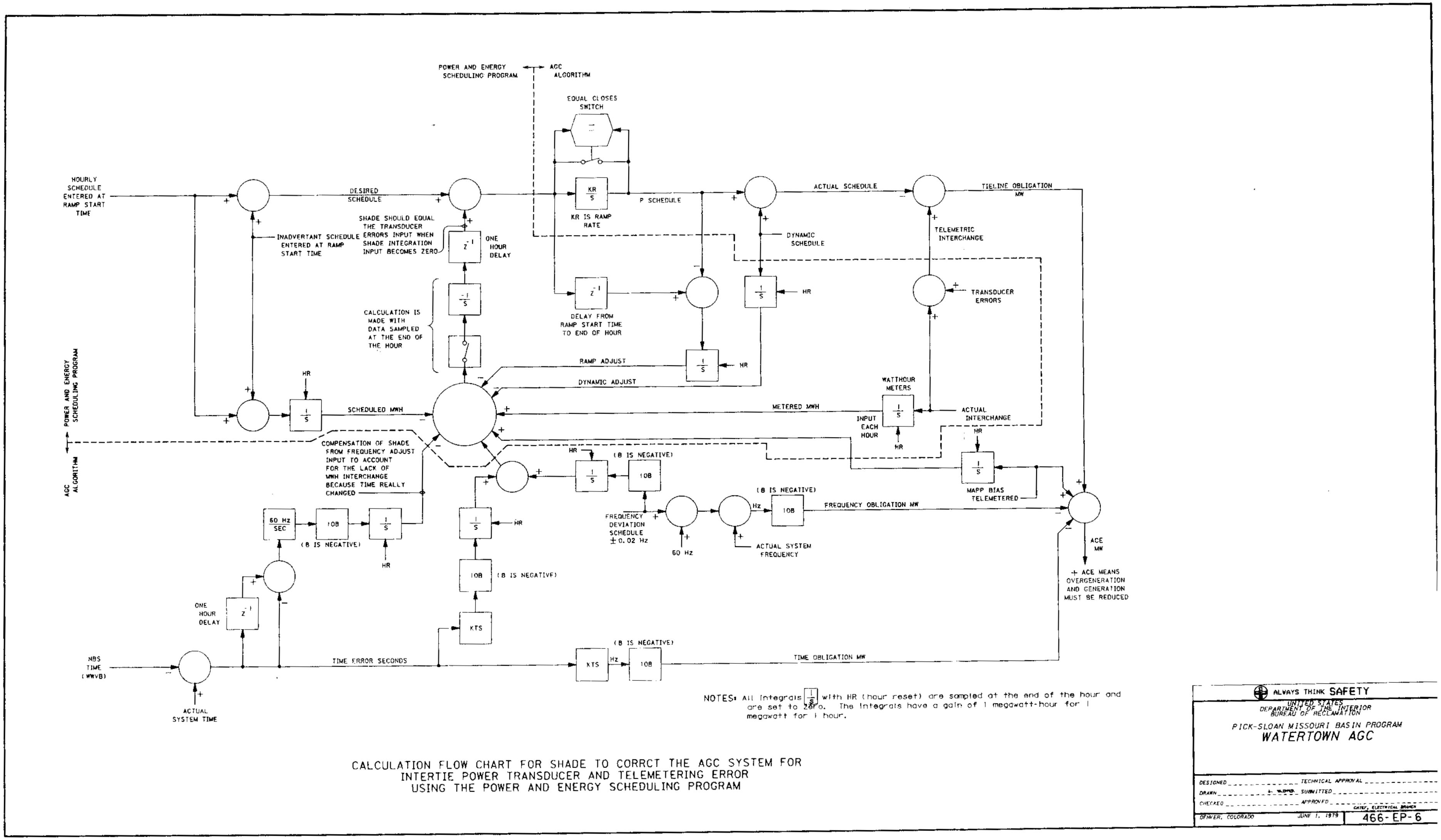
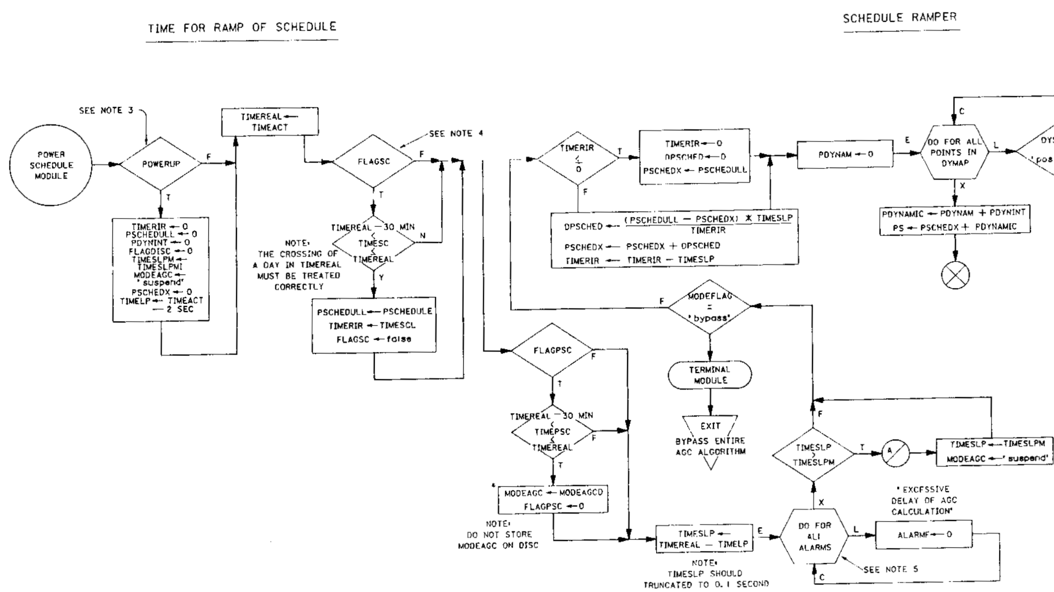


Figure 4.—Power schedule module (Sheet 1 of 2).



NOTES

1. TIMEREAL is the actual time at the start of the algorithm truncated to 1 second. It is constant throughout the algorithm.
2. DYMAP contains address pointers to every DATUMF value used in the dynamic schedule. These may consist of the power output from external joint-owned-units or dynamic loads within the area. DYMAP also allows pointers to DYSIGN, a variable for each DATUMF that allows the sign of the addition to be determined. The DYMAP array and DYSIGN both should be available for change by an engineer while the algorithm is operating.
3. Powerup initializing concepts are explained in the text section 'Initialization.'
4. FLAGSC and TIMESC concepts are explained in the text section 'The Buffers' and in Figure 4.
5. Alarms are discussed in the text section 'The Buffers.'

All integrals $\left[\frac{1}{s}\right]$ with HR (hour reset) are sampled at the end of the hour and are then set to zero.
The integrals have a gain of 1 megawatt-hour for 1 megawatt for 1 hour.

CALCULATION FLOW CHART FOR SHADE TO CORRECT THE AGC STSTEM FOR INTERTIE POWER TRANSDUCER AND TELEMETERING ERROR USING THE POWER AND ENERGY SCHEDULING PROGRAM

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Figure 4.—Power schedule module (Sheet 2 of 2).

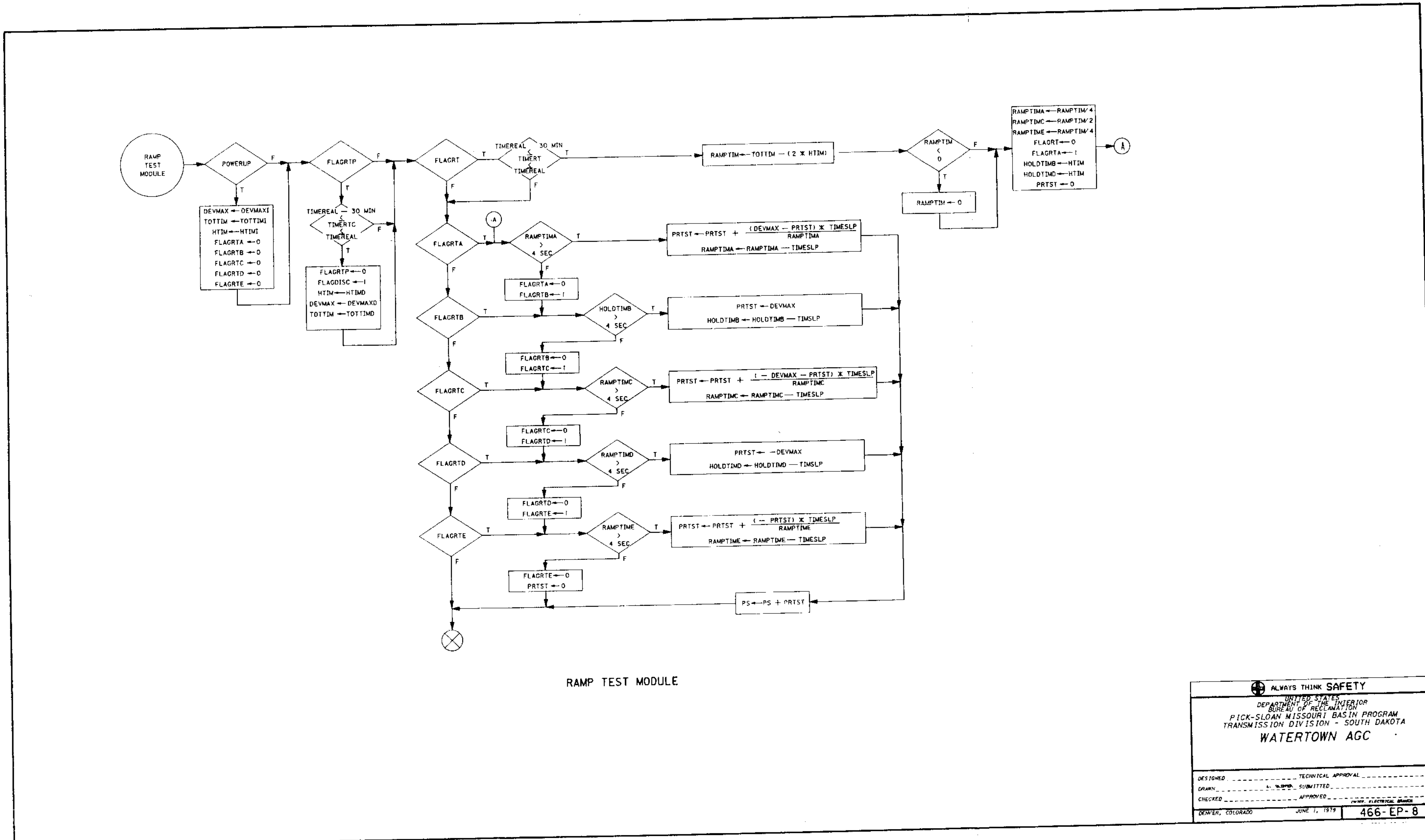


Figure 5.—Ramp test module.

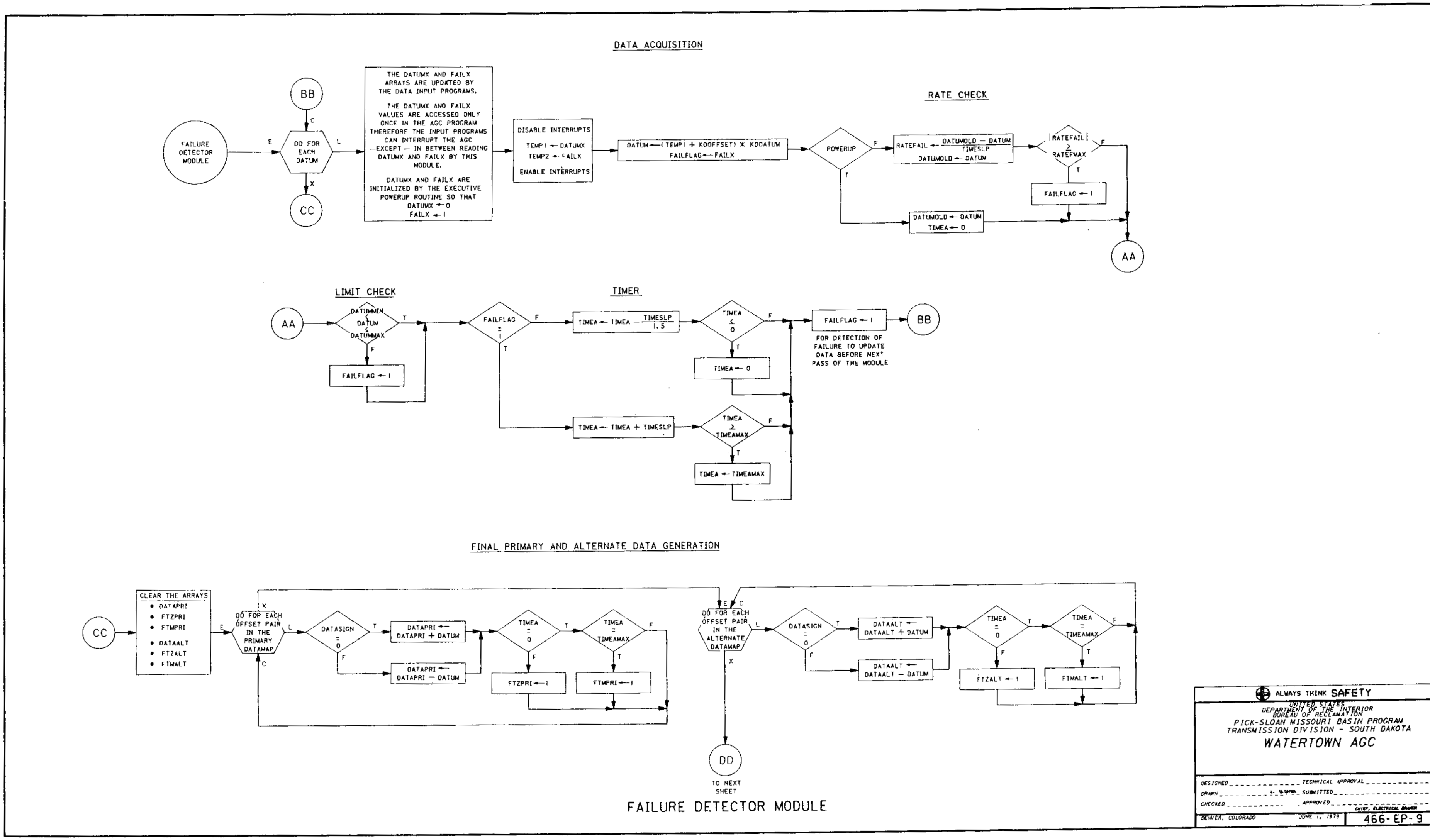
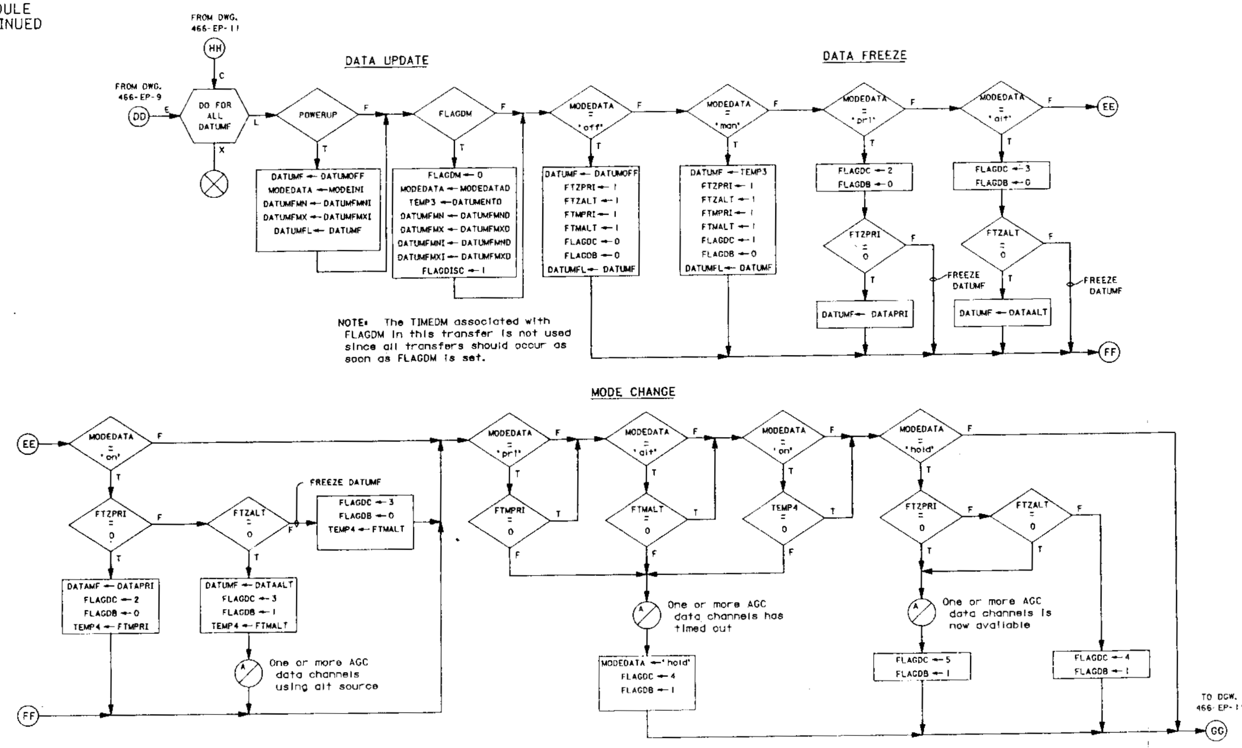


Figure 6.—Failure detector module (Sheet 1 of 6).

FAILURE DETECTOR
MODULE
CONTINUED



COLOR OF DISPLAYS FOR VALUES OF FLAGDC

FLAGDC	DATUMF	DATAPRI	DATAALT	DATUMFMN	DATUMFMX	MODEDATA
0	GREEN	GREEN	GREEN	YELLOW	YELLOW	YELLOW
1	RED	GREEN	GREEN	YELLOW	YELLOW	YELLOW
2	YELLOW	RED	GREEN	YELLOW	YELLOW	YELLOW
3	YELLOW	GREEN	RED	YELLOW	YELLOW	YELLOW
4	YELLOW	GREEN	GREEN	YELLOW	YELLOW	GREEN
5	YELLOW	GREEN	GREEN	YELLOW	YELLOW	RED

BLINKING OF DISPLAYS FOR VALUES OF FLAGD

FLAGDB	BLINK
0	NO BLINK
1	BLINK MODEDATA DISPLAY
2	BLINK DATUMF, DATUMFMX, DATUMFMN
3	BLINK DATUMF

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Figure 6.—Failure detector module (Sheet 2 of 6).

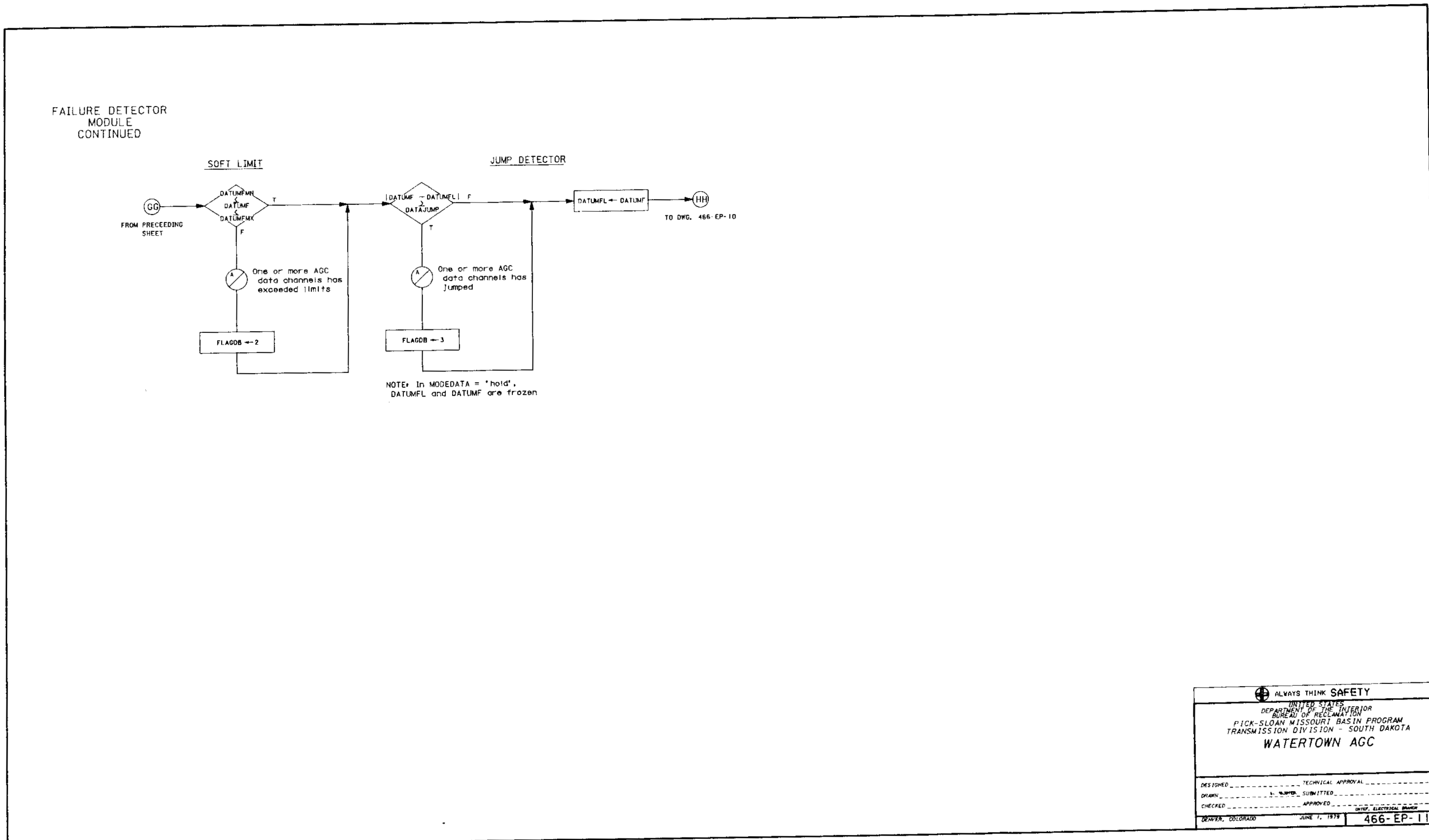


Figure 6.—Failure detector module (Sheet 3 of 6).

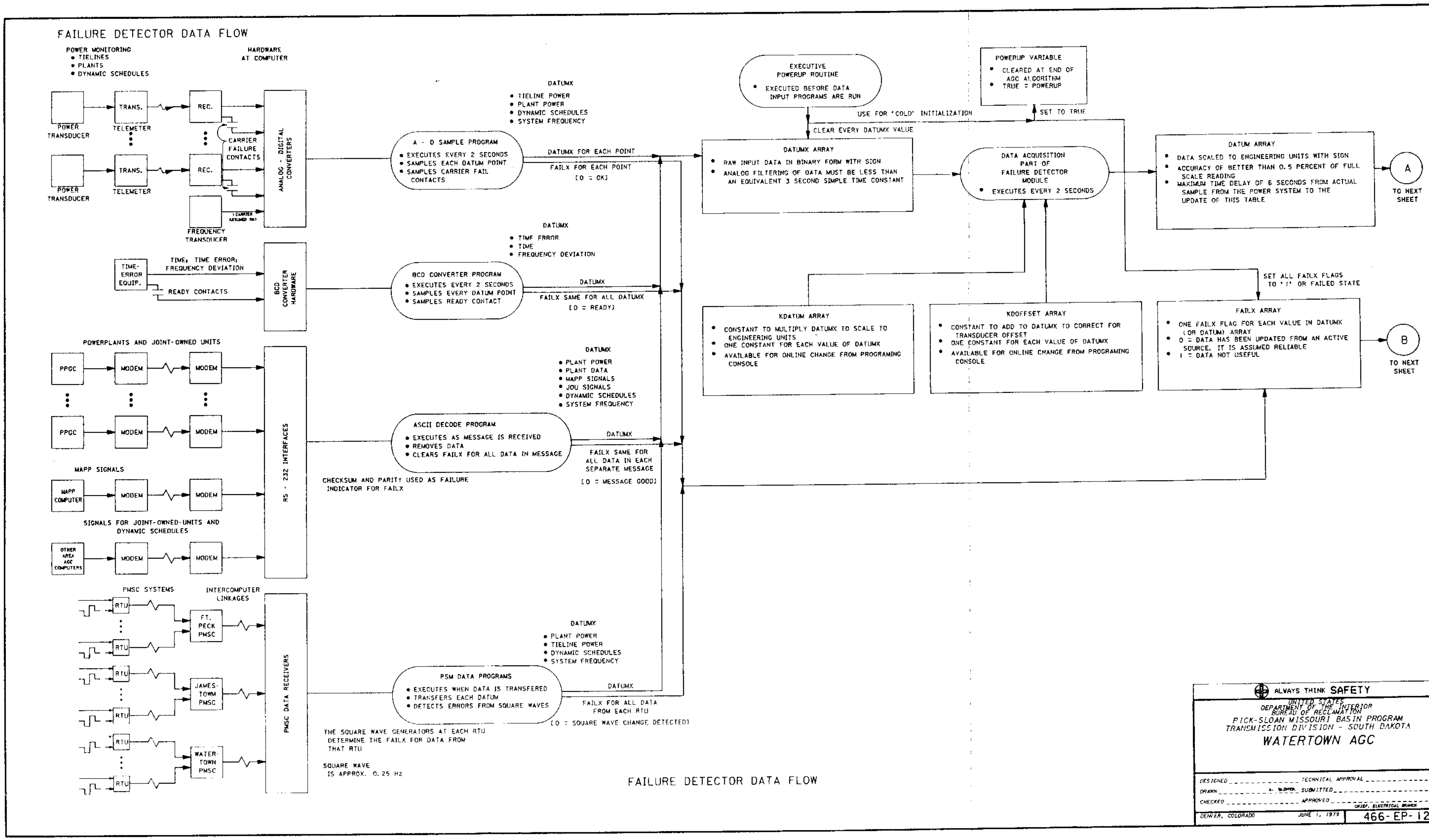


Figure 6.—Failure detector module (Sheet 4 of 6).

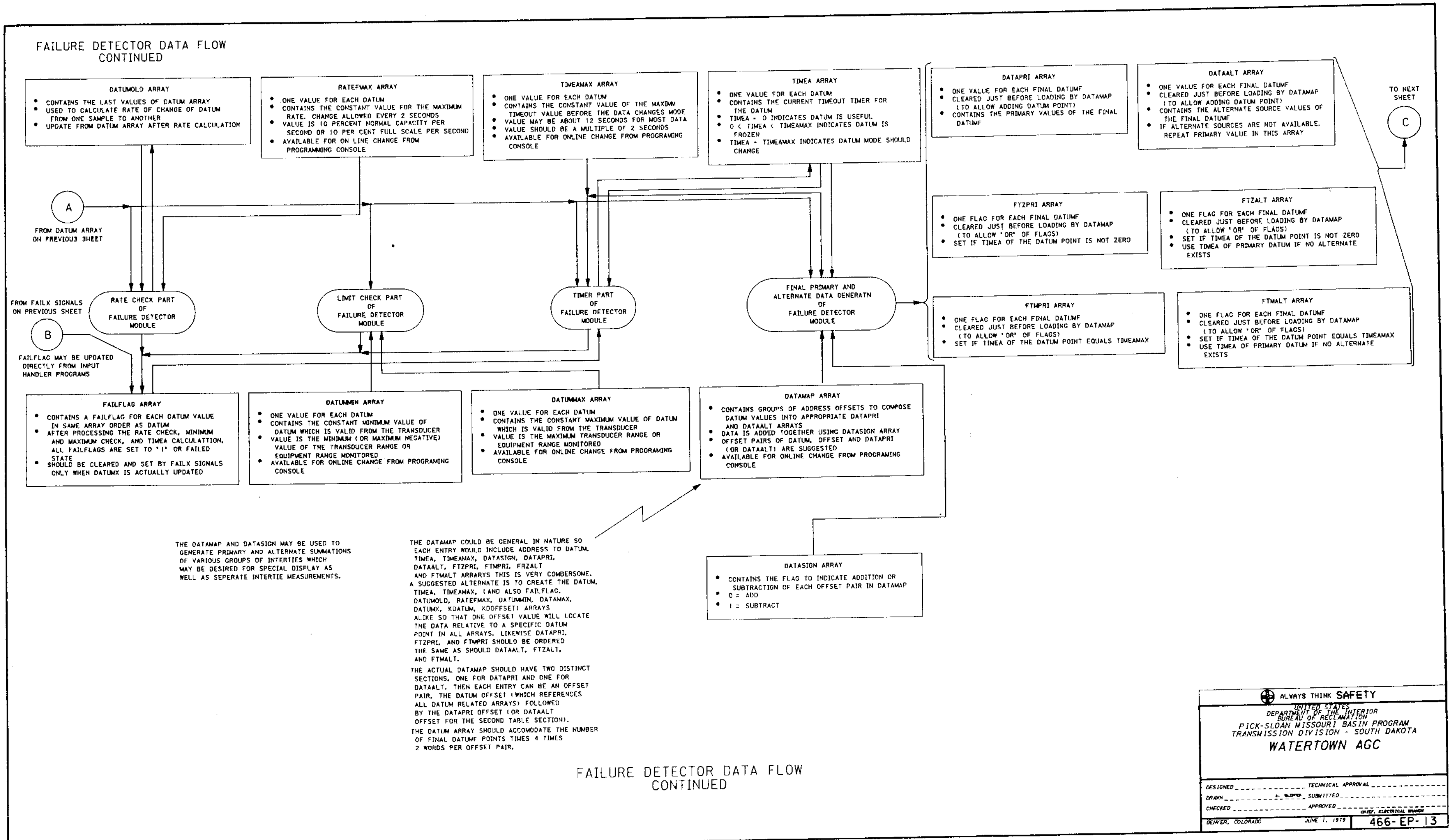


Figure 6.—Failure detector module (Sheet 5 of 6).

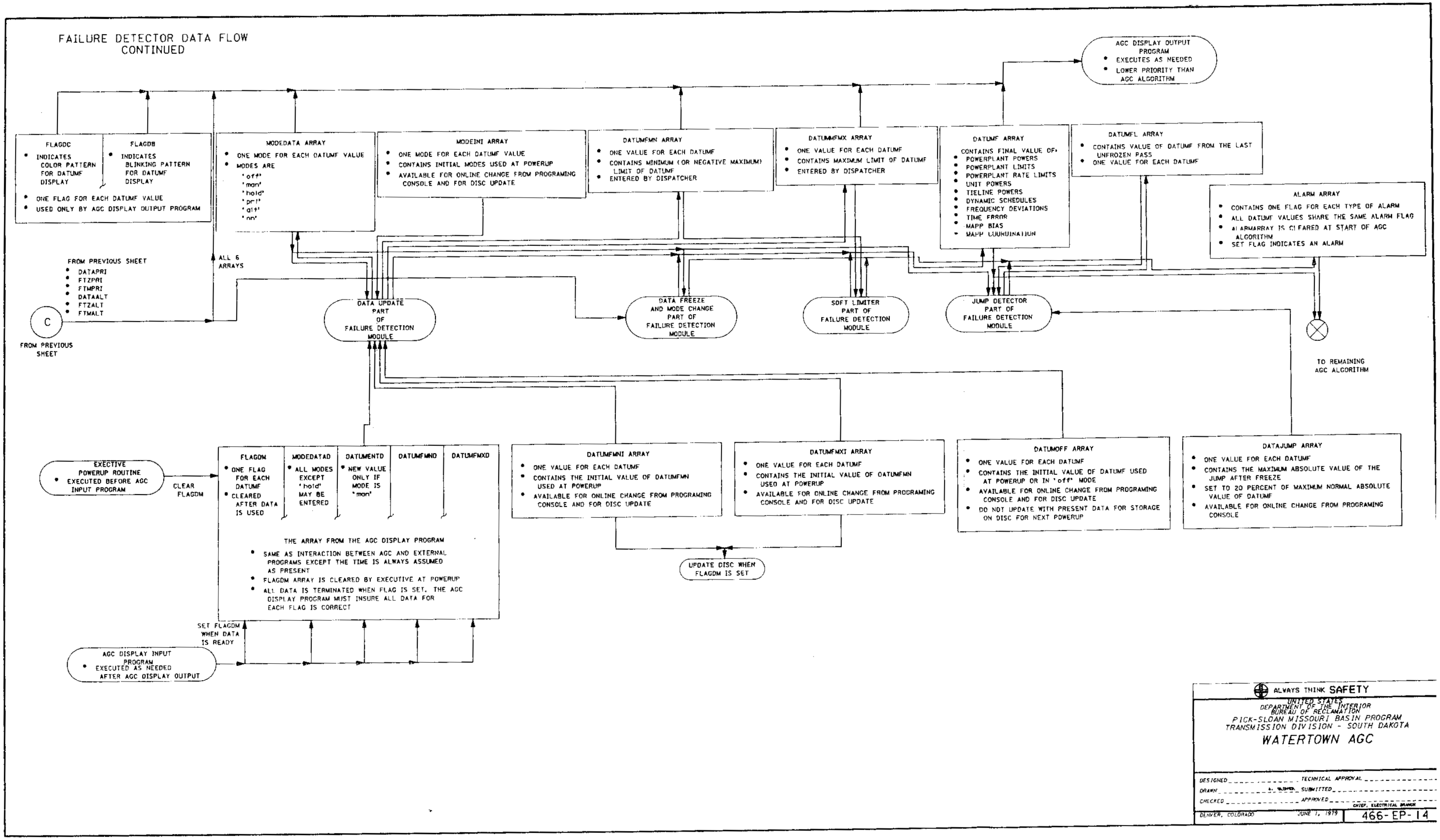


Figure 6.—Failure detector module (Sheet 6 of 6).

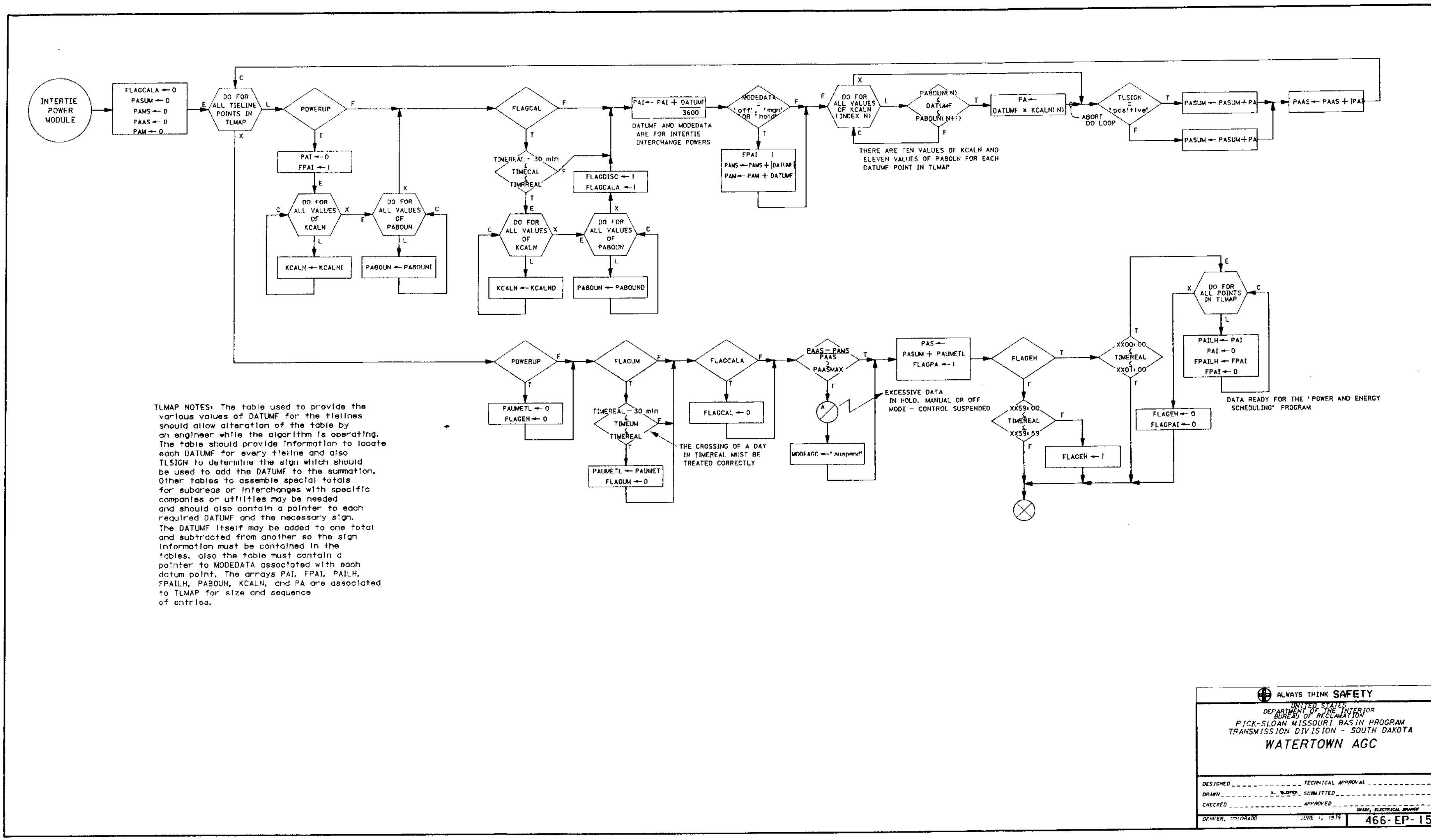


Figure 7.—Intertie power module.

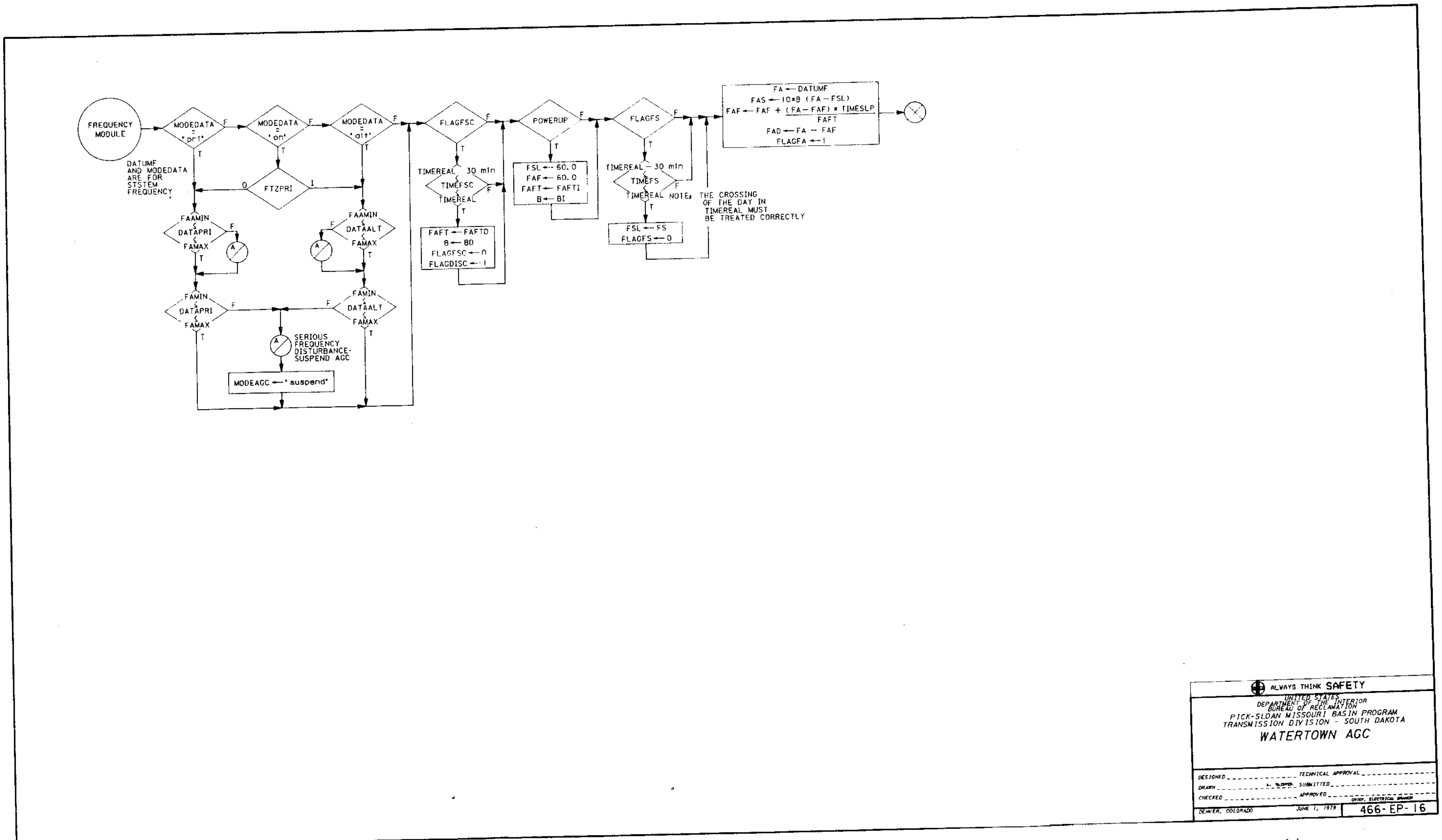


Figure 8.—Frequency module.

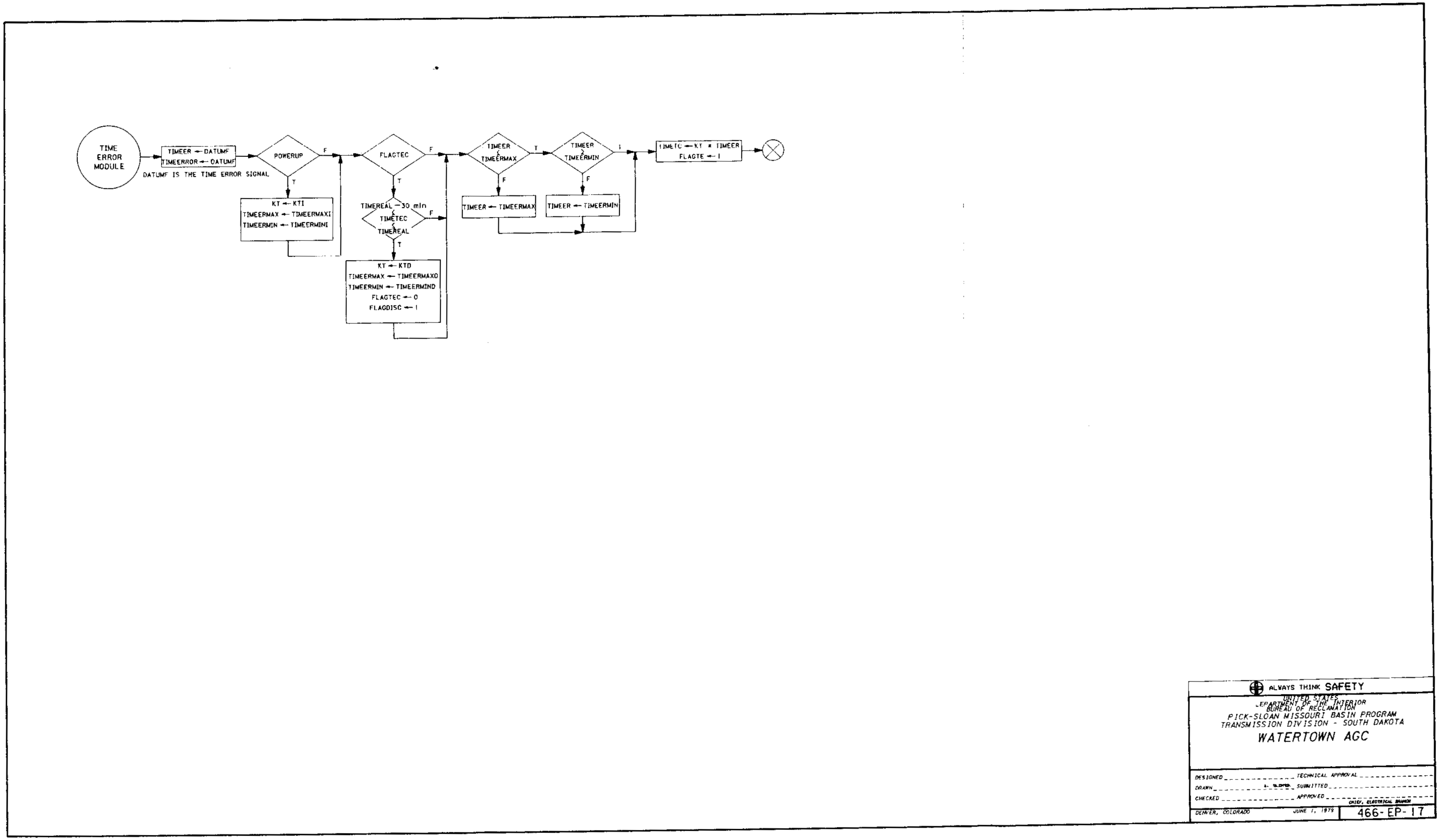
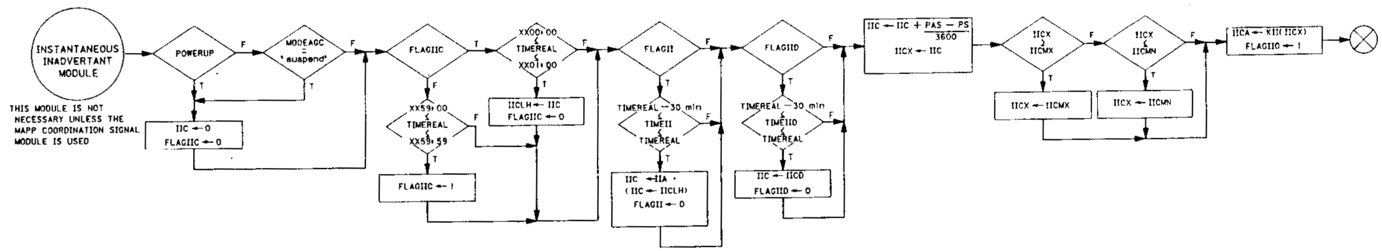


Figure 9.—Time error module.



THE 'POWER AND ENERGY SCHEDULING' PROGRAM MUST EXECUTE ONCE AN HOUR:

- READ ALL MWH READINGS OF ALL INTERTIES
- CHECK MWH READINGS WITH CALCULATED MWH FOR EACH TIE AND ALARM IF ANY DIFFERENCE IS GREATER THAN 2 PERCENT OF NORMAL OR RATED INTERTIE FLOW
- ALLOW DISPATCHER TO CHECK READINGS AND SUBSTITUTE READINGS WHEN NECESSARY
- WHEN DISPATCHER IS SATISFIED, CALCULATE THE METERED ENERGY INTERCHANGE LESS THE ACTUAL SCHEDULED INTERCHANGE INCLUDING RAMPS.

  $$IIA \leftarrow (IMDEL - IMREC) - (PSDEL - PS\ REC)(1\ hr) + \left(\sum_{ALL\ EXT\ JOU} IJOUEXT - \sum_{ALL\ INT\ JOU} IJOUINT\right) + PSRAMPADJ$$

  WHERE THE VALUES ARE THE SAME AS FOR SHADE
- WHEN THE CALCULATION IS COMPLETE, FLAGII ← 1, AND TIMEII ← TIMEREAL

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Figure 10.—Instantaneous inadvertant module.

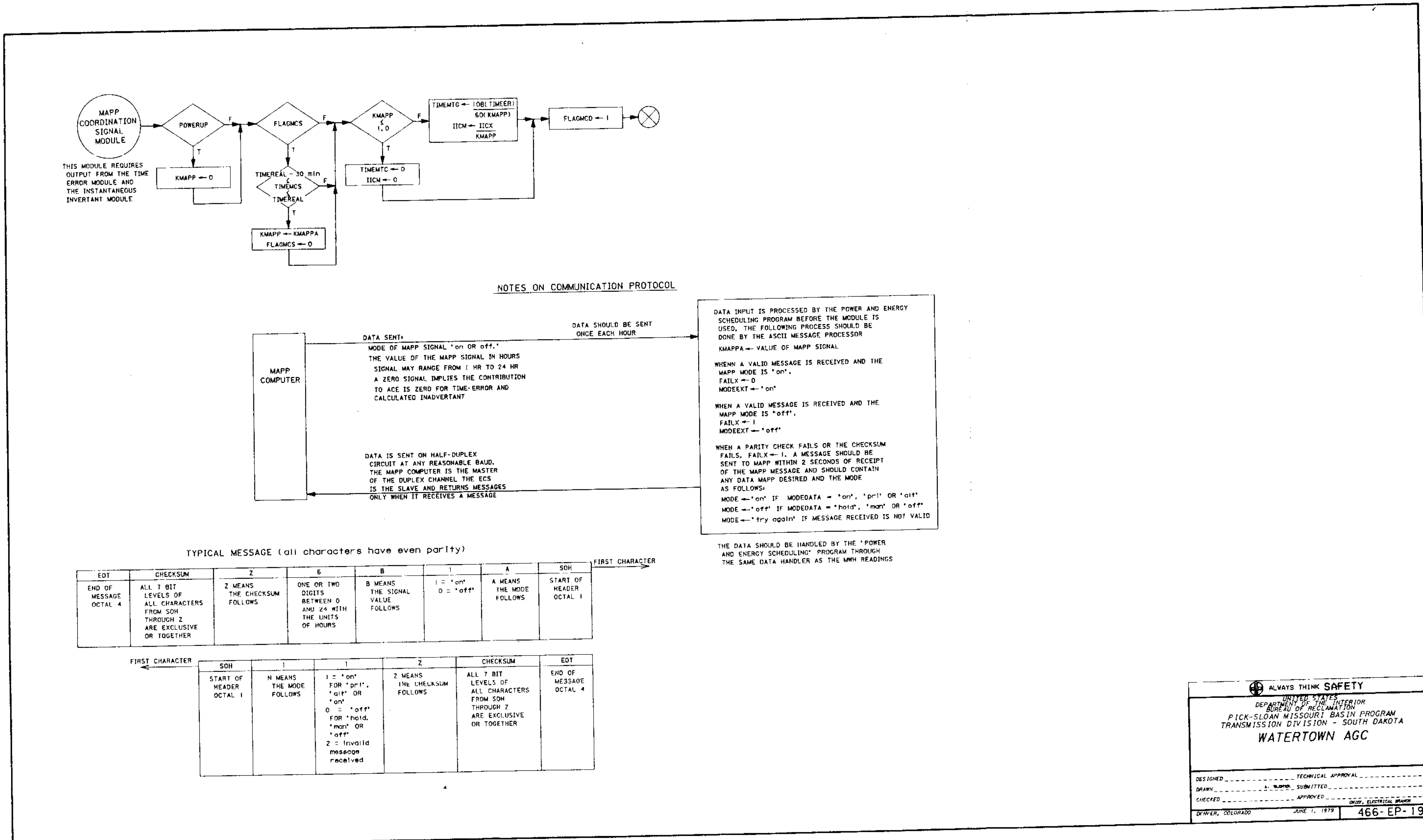
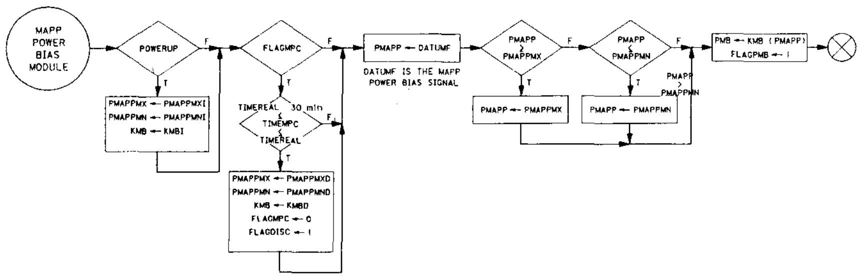


Figure 11.—MAPP coordination signal module.



NOTES ON COMMUNICATION PROTOCOL

MAPP COMPUTER

DATA SHOULD BE SENT ONCE EACH 2 SECONDS

DATA SENT: MODE OF MAPP POWER BIAS SIGNAL 'on' OR 'off'. THE VALUE OF THE MAPP POWER BIAS SIGNAL IN MW.

DATA INPUT IS PROCESSED BY THE FAILURE DETECTOR MODULE. BEFORE THE MODULE IS USED, THE FOLLOWING PROCESS SHOULD BE DONE BY THE ASCII MESSAGE PROCESSOR:

DATUMX ← VALUE OF MAPP POWER BIAS

WHEN A VALID MESSAGE IS RECEIVED AND THE MAPP MODE IS 'on',
FAILX ← 0,
MODEEXT ← 'on'

WHEN A VALID MESSAGE IS RECEIVED AND THE MAPP MODE IS 'off',
FAILX ← 1,
MODEEXT ← 'off'

WHEN A PARITY CHECK FAILS OR THE CHECKSUM FAILS,
FAILX ← 1

A MESSAGE SHOULD BE SENT TO MAPP WITHI 1.5 SECONDS AFTER RECEIPT OF THE MAPP *MESSAGE AND SHOULD CONTAIN ANY DATA MAPP DESIRED AND THE MODE AS FOLLOWS:*
MODE ← 'on' IF MODEDATA = 'on', 'prl' OR 'alt'.
MODE ← 'off' IF MODEDATA = 'hold', 'man' OR 'off'.

DATA IS SENT ON A HALF-DUPLEX CIRCUIT AT ANY REASONABLE BAUD. THE MAPP COMPUTER IS THE MASTER OF THE DUPLEX CHANNEL. THE ECS IS THE SLAVE AND RETURNS MESSAGES *ONLY WHEN IT RECEIVES A MESSAGE.*

NOTE: MODEEXT IS EXPLAINED IN THE PLANT DATA MODULE.
MODEDATA1 ← 'off'
DATUMOFF ← 0

TYPICAL MESSAGE (all characters have even parity)

EOT	CHECKSUM	Z	7	2	—	D	1	C	SOH
END OF MESSAGE OCTAL 4	ALL 7BIT LEVELS OF ALL CHARACTERS FROM SOH THROUGH Z ARE EXCLUSIVE OR TOGETHER	Z MEANS THE CHECKSUM FOLLOWS	THE MAPP BIAS VALUE −27 MW.			D MEANS THE MAPP BIAS FOLLOWS	1 = 'on' 0 'off'	C MEANS THE MODE FOLLOWS	START OF HEADER OCTAL 1

FIRST CHARACTER →

← *FIRST CHARACTER*

SOH	P	1	Z	CHECKSUM	EOT
START OF HEADER OCTAL 1	P MEANS THE MODE FOLLOWS	1 'on' FOR 'prl', 'alt' OR 'on' 0 = 'off' FOR 2'hold', 'man' OR 'off'.	Z MEANS THE CHECKSUM FOLLOWS	ALL 7BIT LEVELS OF ALL CHARACTERS FROM SOH THROUGH Z ARE EXCLUSIVE OR TOGETHER	END OF MESSAGE OCTAL 4

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Figure 12.—MAPP power bias module.

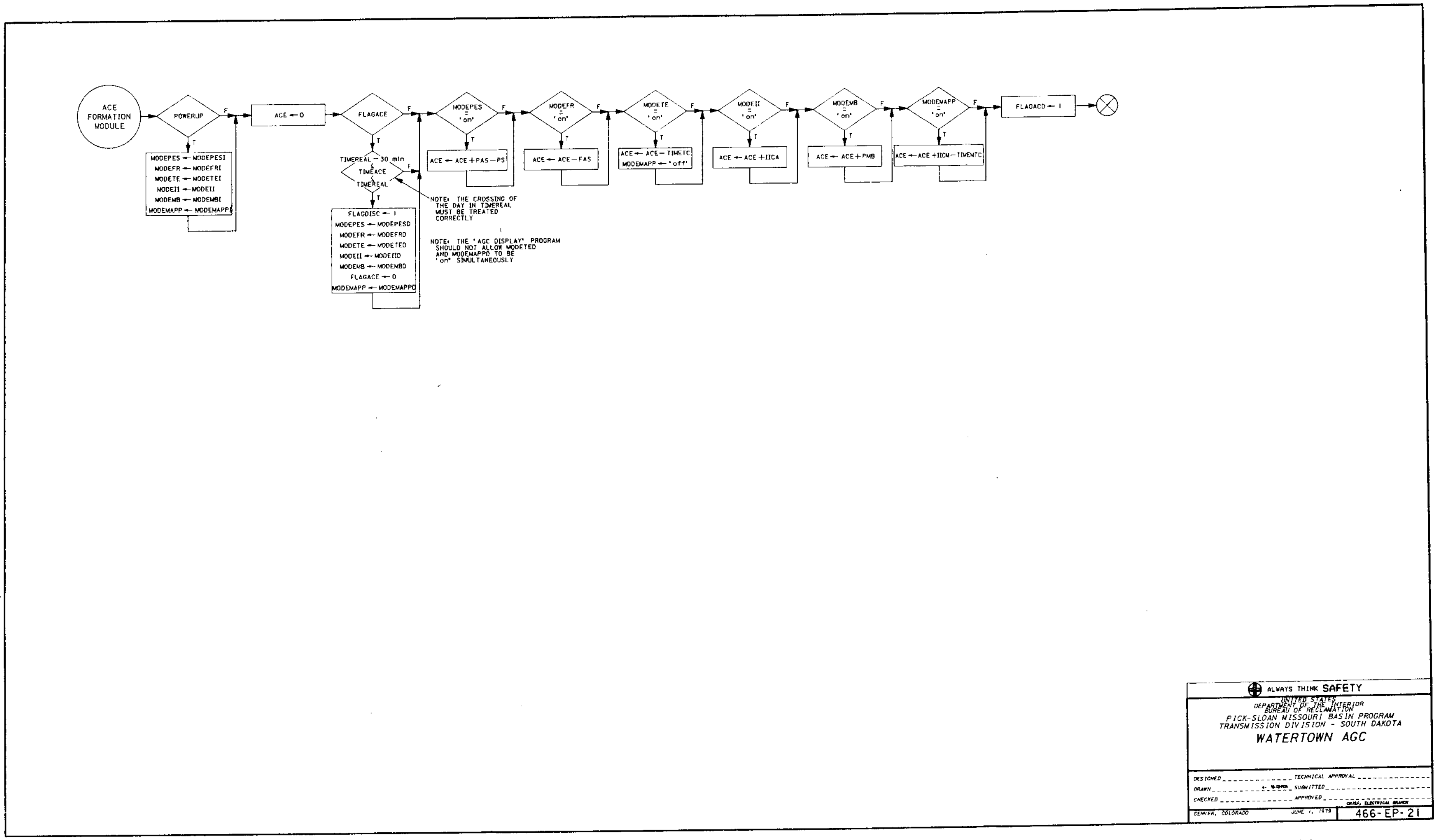


Figure 13.—ACE formation module.

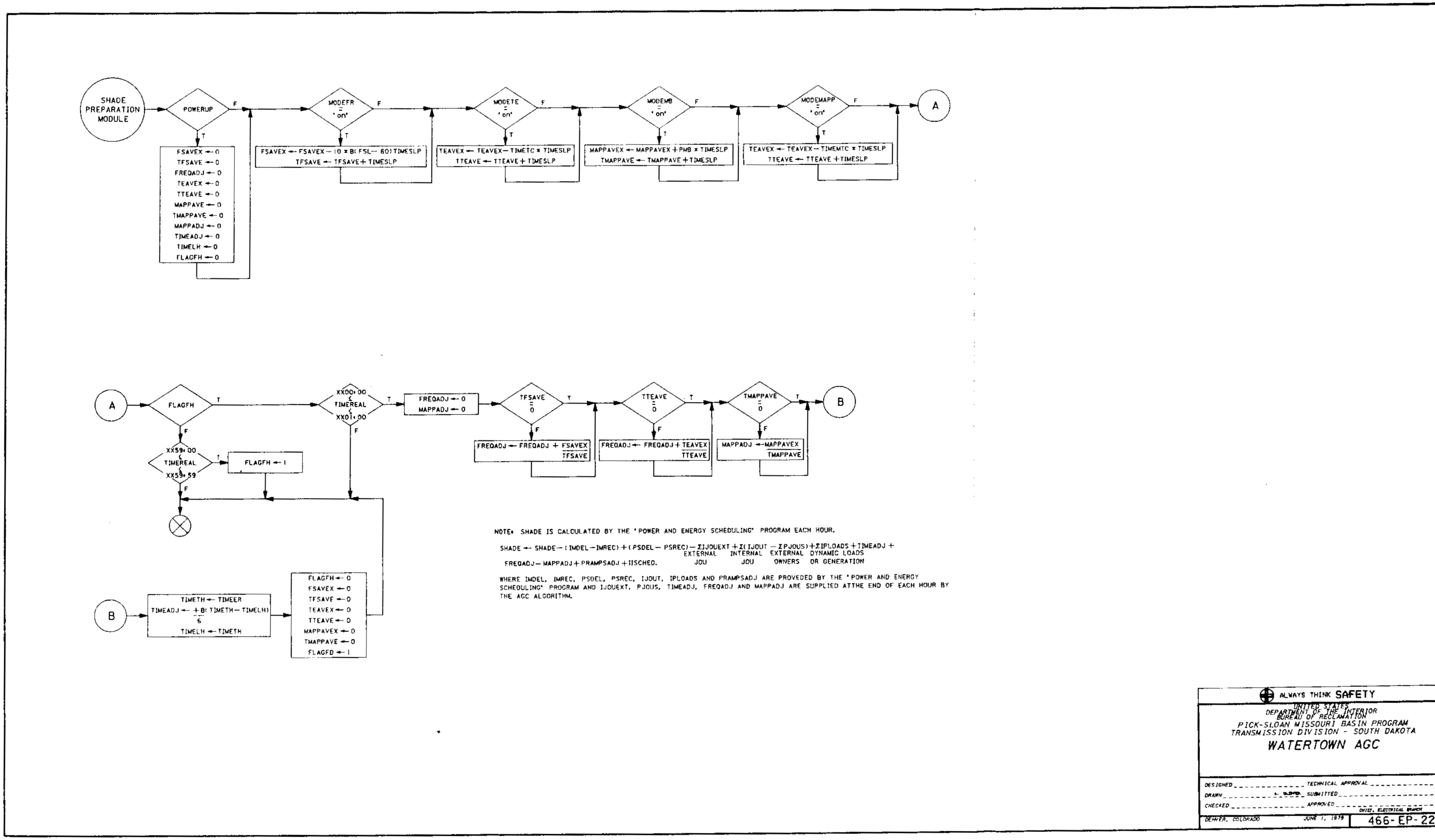


Figure 14.—SHADE preparation module.

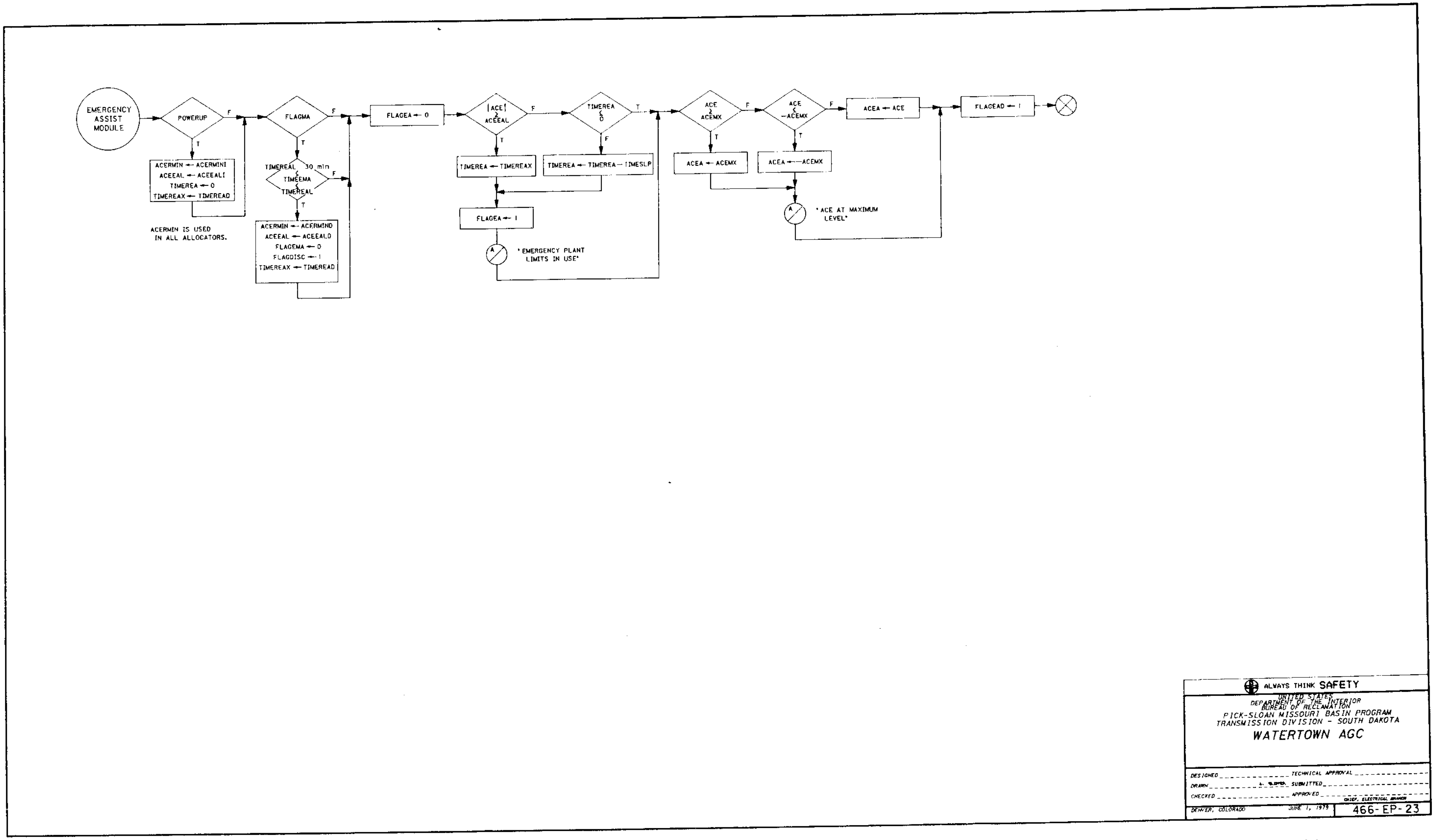


Figure 15.—Emergency assist module.

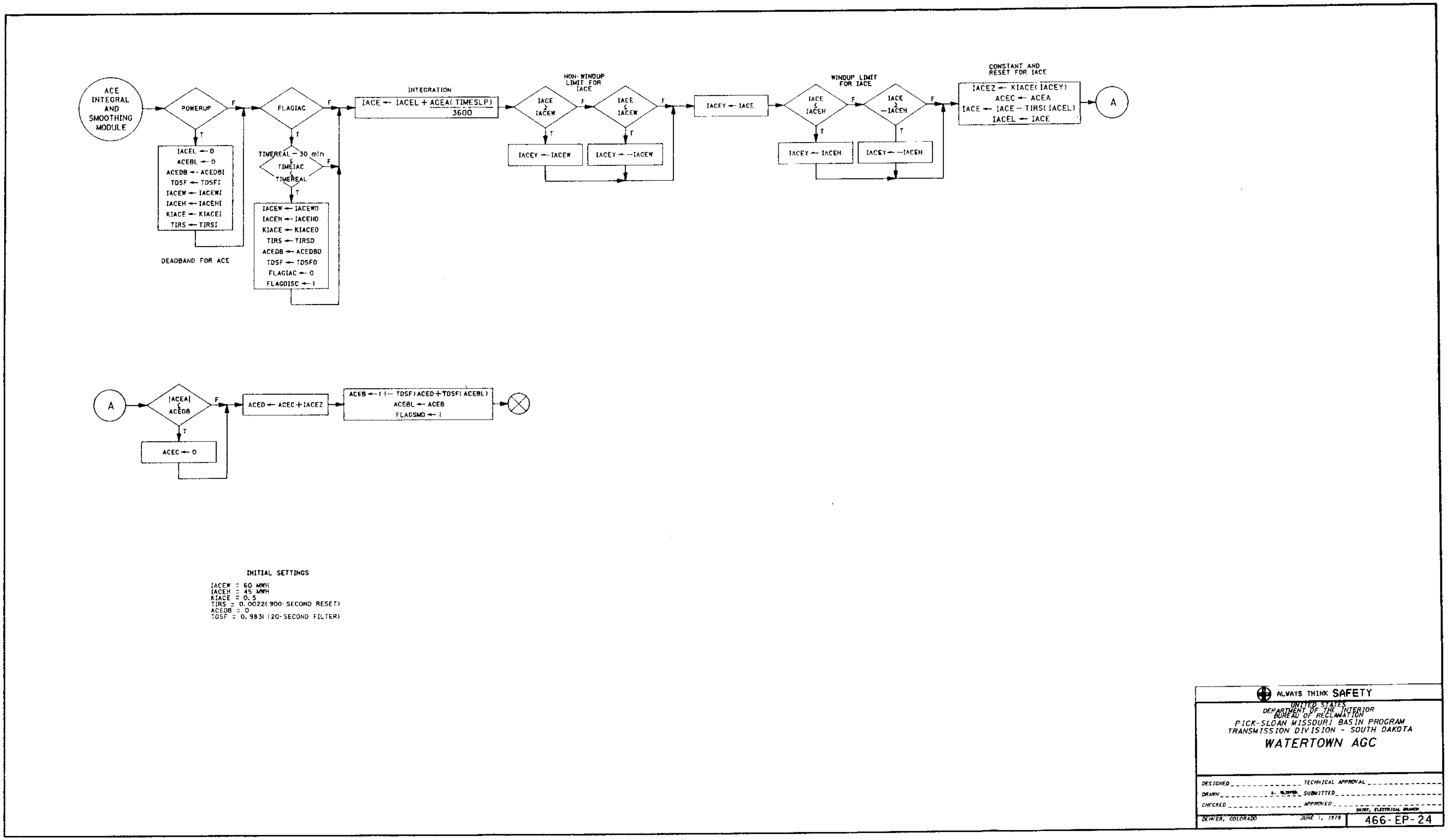


Figure 16.—ACE integral and smoothing module.

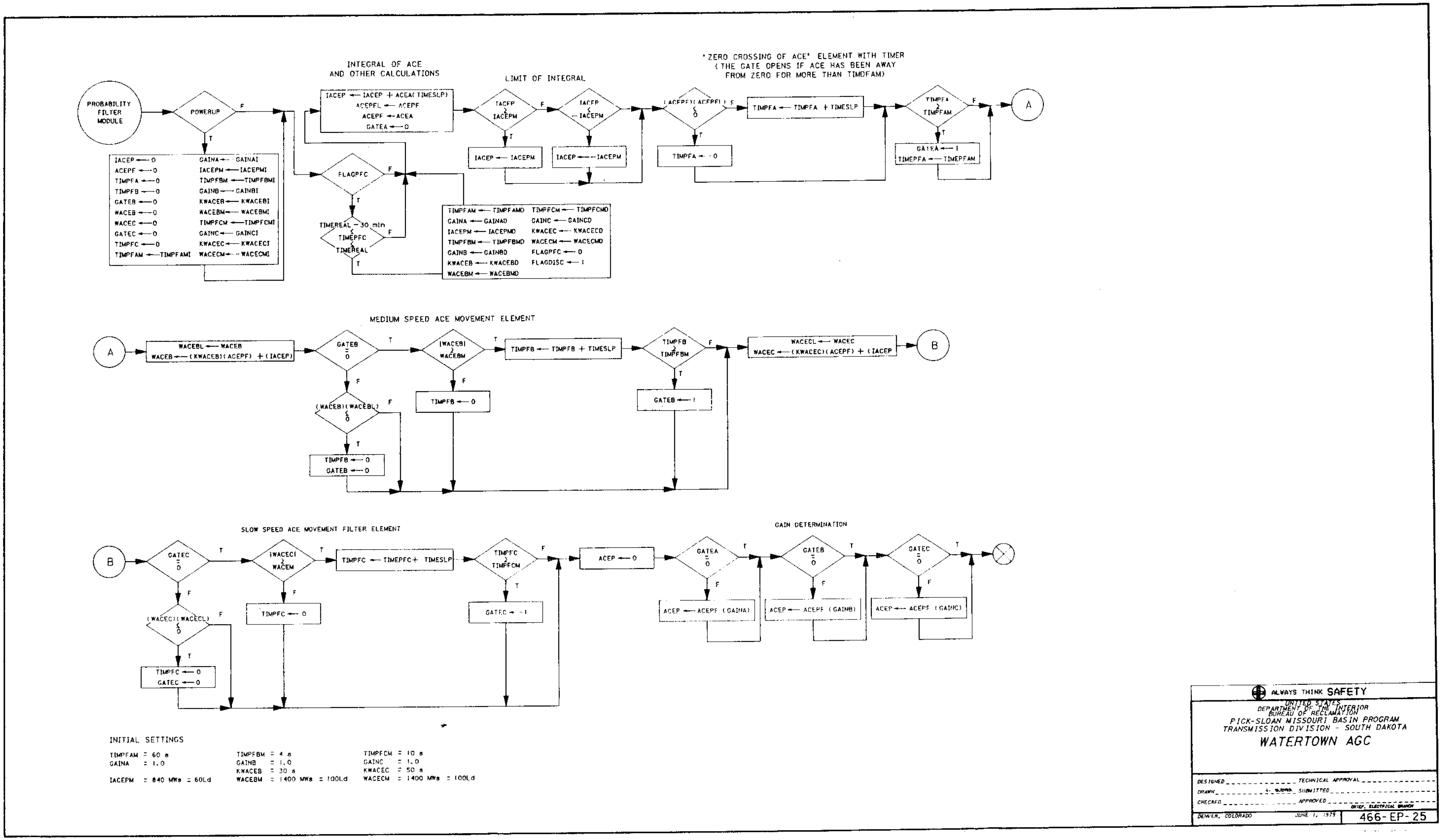


Figure 17.—Probability filter module.

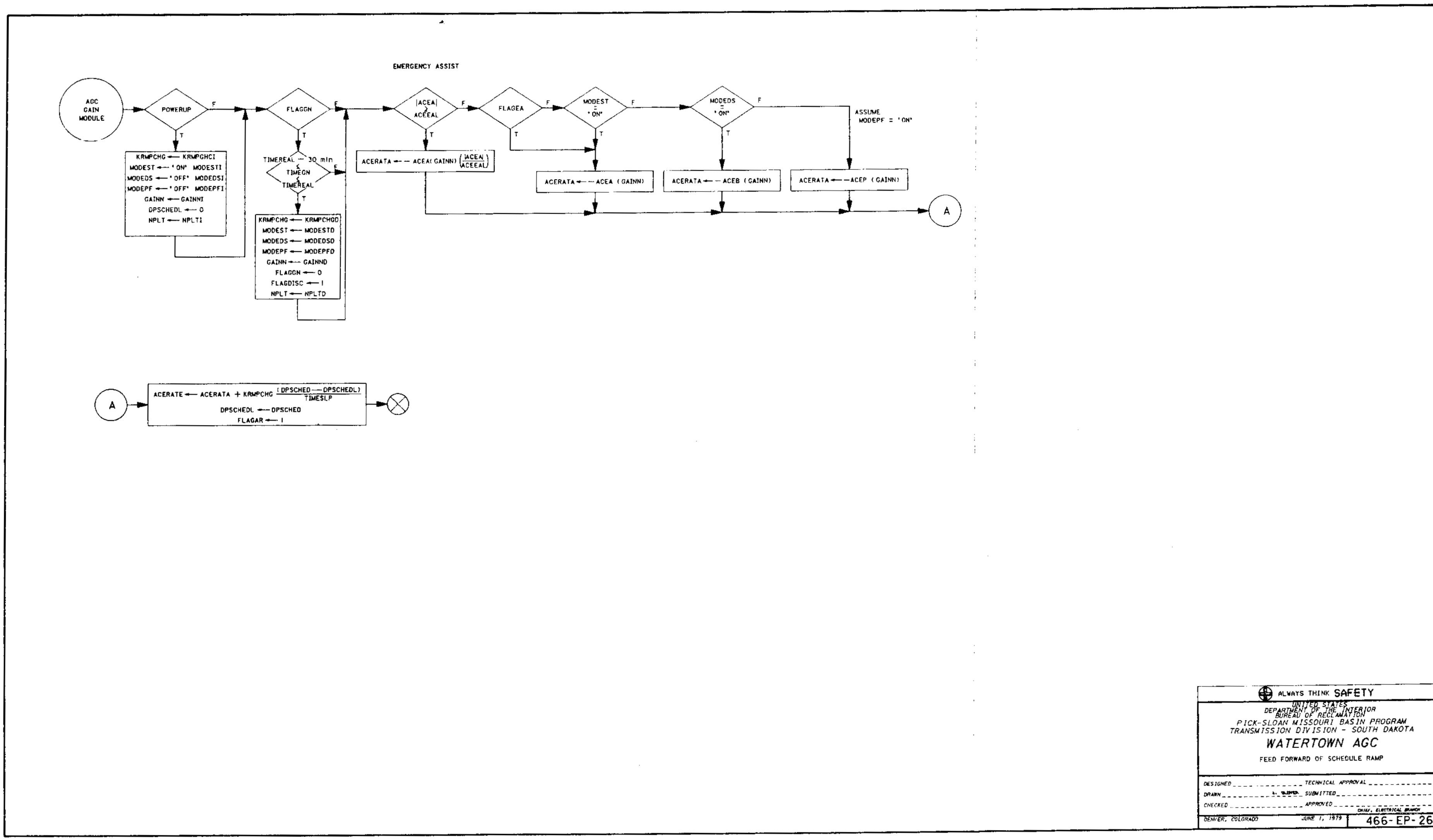


Figure 18.—AGC gain module.

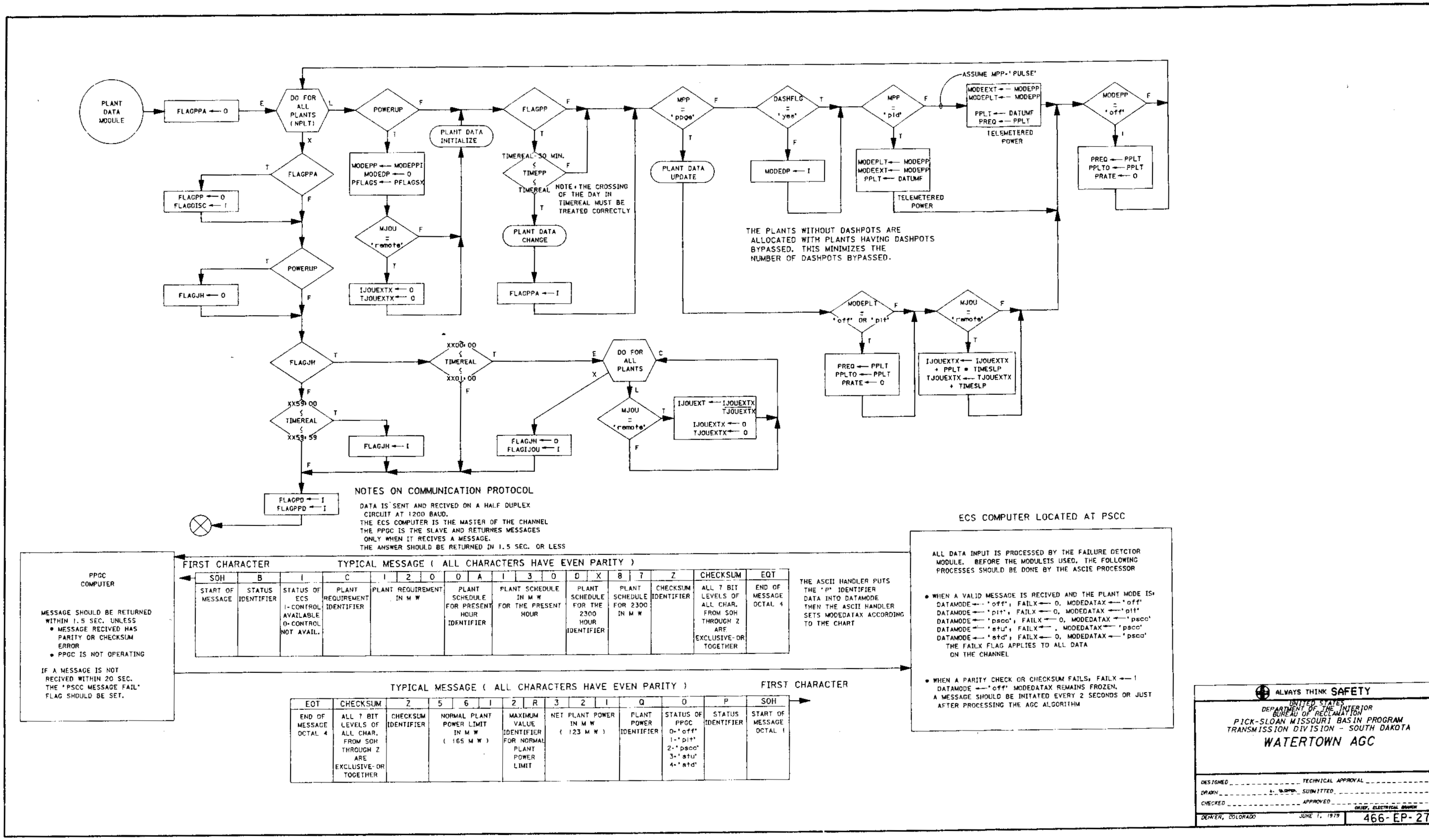
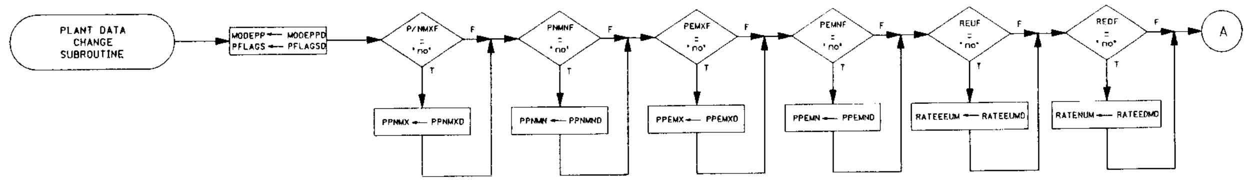
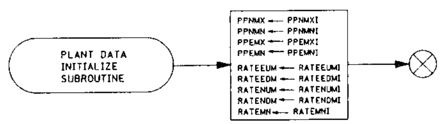
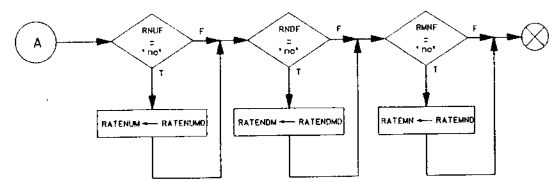


Figure 19.—Plant data module (Sheet 1 of 3).







NOTE

THE VARIABLE PFLAGS HAS THE POWERPLANT CONCERNING THE TYPE OF PLANT AND SOURCE OF PLANT DATA. PFLAGS ALSO CONTAINS INFORMATION FOR SPECIFIC GENERATORS IN GENERATION CONTROL DATA FORMAT MODULE AND OTHER MODULES.

GENERAL PLANT DATA					POWER LIMIT DATA FROM PLANT				RATE LIMIT DATA FROM PLANT					SCHEDULE TO PLANT		INDIVIDUAL GENERATOR DATA FROM PLANT		PLANT FREQ
TYPE OF CONTROL	JOINT-OWNED UNIT STATUS	PRESENCE OF DASHPOT	DASHPOT DATA FROM PLANT	EMMER. ASSIST FLAG SENT TO PLANT	NORMAL MAXIMUM POWER	NORMAL MINIMUM POWER	EMERGENCY MAXIMUM POWER	EMERGENCY MINIMUM POWER	NORMAL UPWARD RATE	NORMAL DOWNWARD RATE	EMERGENCY UPWARD RATE	EMERGENCY DOWNWARD RATE	MINIMUM RATE	NEXT HOUR TO PLANT	24 HOUR TO PLANT	GENERATOR STATUS TRANSMITTED	GENERATOR POWER OUTPUT TRANSMITTED	FREQUENCY BIASING STPT AT PLANT
MPP	MJOV	DASHFLG	DASHFD	EAFLG	PNMKF	PNMNF	PEMXF	PEMNF	RNUF	RNDF	REUF	REDF	RMNF	SNHF	SALLF	USTAT	UGEN	FRFLG
'ppgc'	'not' 'local' 'remote'	'yes'} 'no'}	'yes' 'no' —	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'	'yes' 'no'
'pld' 'pulse'	— —	'yes' 'no' 'yes' 'no'	— —	'yes' 'no' 'yes' 'no'	'no'	'no'	'no'	'no'	'no'	'no'	'no'	'no'	'no'	'no'	'no'	'no'	'Yes'	'no'

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Figure 19.—Plant data module (Sheet 2 of 3).

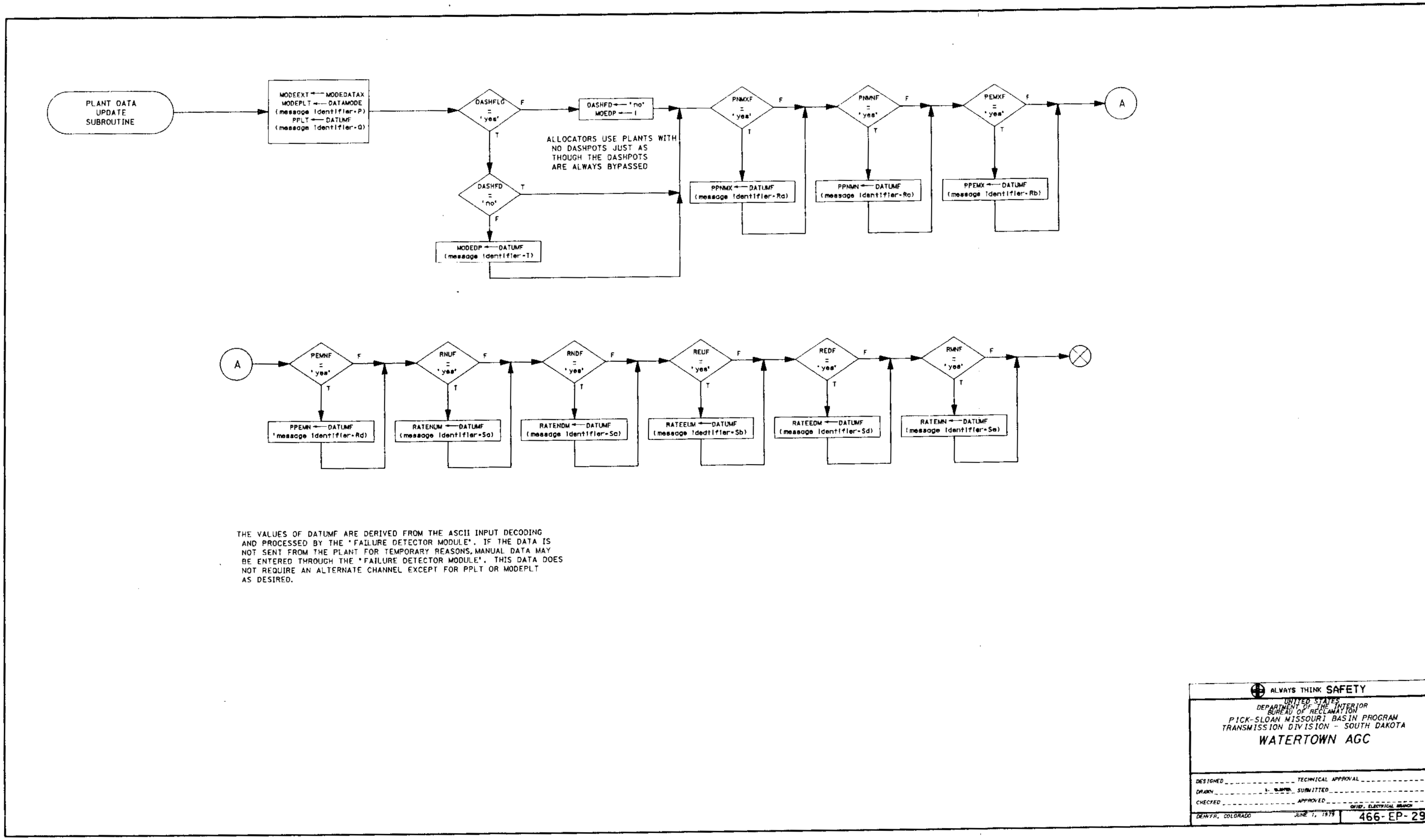
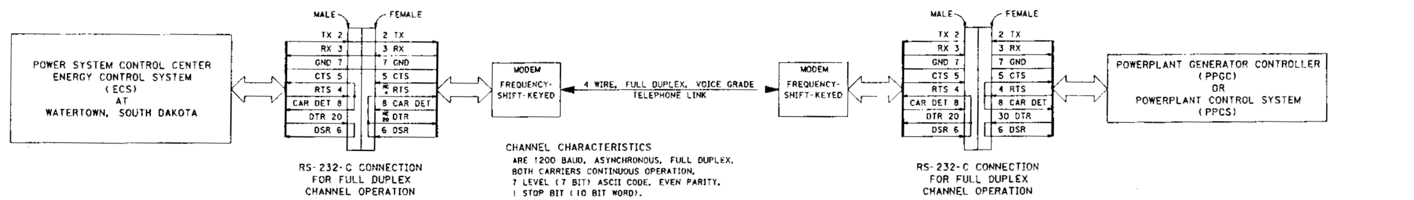


Figure 19.—Plant data module (Sheet 3 of 3).

POWERPLANT COMMUNICATIONS LINK CHARACTERISTICTS FOR THE AGC ALGORITHM



RS-232-C CONNECTION
FOR FULL DUPLEX
CHANNEL OPERATION

RS-232-C CONNECTION
FOR FULL DUPLEX
CHANNEL OPERATION

CHANNEL CHARACTERISTICS
ARE 1200 BAUD, ASYNCHRONOUS, FULL DUPLEX, BOTH CARRIERS CONTINUOUS OPERATION, 7 LEVEL (7 BIT) ASCII CODE, EVEN PARITY, 1 STOP BIT (10 BIT WORD).

OPERATING CHARACTERISTICS
ARE HALF DUPLEX MESSAGE ANSWERING BETWEEN COMPUTERS TO SIMPLIFY SOFTWARE IN BOTH COMPUTERS. HOWEVER, THE FULL DUPLEX HARDWARE WILL ALLOW MESSAGES TO OVERLAP WHN NECESSARY TO SIMPLIFY TIMING.

MESSAGE CHARACTERISTICS
THE ENERGY CONTROL SYSTEM SENDS THE VARIABLE LENGTH MESSAGE EVERY 2 SECONDS.

ASCII CHARACTER	EOT	CHECKSUM	Z	7(DIGIT)	1(DIGIT)	3(DIGIT)	3	1(DIGIT)	B	SOH
OCTAL CODE	204	336	132	267	261	063	303	261	102	201
	(END OF TRANSMISSION)									(START OF HEADER)

ECS ERROR PROTOCOL
IF A VALID MESSAGE IS NOT RECEIVED FROM THE PPGC AFTER 20 SECONDS, (10 MESSAGES SENT FROM THE ECC), THE CHANNEL SHALL BE ASSUMED DEAD. WHEN THE FIRST INVALID MESSAGE IS RECEIVED (PARITY OR CHECKSUM ERROR) OR WHEN NO MESSAGE IS RECEIVED IN 4.5 SECONDS, THE FAILX FLAG FOR THE DATA IN THE MESSAGE SHALL SET. SEE THE FAILURE DETECTOR MODULE FLOW CHART. WHEN A VALID MESSAGE IS RECEIVED, THE FAILX FLAG SHALL BE CLEARED.

MESSAGE CHARACTERISTICS
THE POWERPLANT GENERATOR CONTROLLER RESPONDS ONLY WHEN A VALID MESSAGE IS RECEIVED. THE RESPONSE MUST START IN LESS THAN 1.5 SECONDS AFTER RECIEPT OF THE LAST CHACTER OF THE MESSAGE. THIS IS TO INSURE THE MESSAGE INTERCHANGE WILL BE COMPLETED WITHIN 2 SECONDS.

FIRST CHARACTER

SOH	P	2(DIGIT)	Q	3(DIGIT)	1(DIGIT)	5(DIGIT)	Z	CHECKSUM	EOT	ASCII CHARACTER
201	120	262	321	063	261	065	132	137	204	OCTAL CODE

PPGC ERROR PROTOCOL
IF INVALID MESSAGES ARE RECEIVED (PARITY OR CHECKSUM ERROR) OR IF NO MESSAGE IS RECEIVED FOR 20 SECONDS, THE CHANNEL SHALL BE ASSUMED DEAD. NO MESSAGES SHALL BE SENT TO THE ECS UNTIL A VALID MESSAGE IS RECEIVED. AFTER THE 20 SECONDS, THE 'PSCC CARRIER FAILURE' FLAG SHALL BE SET FOR THE LOAD CONTROL ALGORITHM EVEN THOUGH THE ACTUAL CARRIER MIGHT STILL BE PRESENT. THE 'PSCC CARRIER FAILURE' FLAG SHALL NOT BE CLEARED UNTIL A VALID MESSAGE IS RECEIVED.

MESSAGE CONTENTS - BOTH MESSAGES

EACH MESSAGE SHALL START WITH 'SOH' AND END WITH 'EOT'

IDENTIFIER	MEANING
Z (REQUIRED)	CHECKSUM - AN EXCLUSIVE-OR OPERATION ON THE 7 BIT ASCII CODES OF EACH CHARACTER RECEIVED INCLUDING 'SOH' THROUGH 'Z'. EVEN PARITY IS THEN ATTACHED.

FOR INCREASED SECURITY, THE OPTIONAL DATA WHICH IS SENT AT INTERVALS GREATER THAN 60 SECONDS SHOULD BE INCLUDED IN AT LEAST THREE CONSECUTIVE MESSAGES.

MESSAGE CONTENTS - ECS MESSAGE

IDENTIFIER	MEANING
B (REQUIRED EVERY 2 SECONDS)	ECS STATUS - 0 - off (NO CONTROL AVAILABLE) 1 - on (CONTROL AVAILABLE)
C (REQUIRED EVERY 2 SECONDS)	PLANT MW REQUIREMENT FROM ECS IN WHOLE MEGAWATTS
D (OPTIONAL)	PLANT SCHEDULE: a - FIRST HOUR, b - SECOND HOUR, c - THIRD HOUR, ..., x - 23rd HOUR, y - ADDITIONAL HOUR FOR DAYLIGHT SAVINGS, A - PRESENT HOUR, B - NEXT HOUR
E (OPTIONAL)	EMERGENCY ASSIST STATUS - 0 - NO ASSIST 1 - ASSIST NEEDED

MESSAGE CONTENTS - PPGC MESSAGE

IDENTIFIER	MEANING
P (REQUIRED EVERY 2 SECONDS)	LOAD CONTROL STATUS - 0 - off 1 - plt 2 - pscc 3 - stu 4 - std
Q (REQUIRED EVERY 2 SECONDS)	TOTAL PLANT POWER IN WHOLE MEGAWATTS
R (OPTIONAL)	MAXIMUM AND MINIMUM PLANT MEGAWATT LIMITS WHICH MAY BE AVAILABLE FROM LOAD CONTROL OR OTHER ALGORITHMS a - NORMAL MAXIMUM c - NORMAL MINIMUM b - EMERGENCY MAXIMUM d - EMERGENCY MINIMUM
S (OPTIONAL)	MAXIMUM AND MINIMUM PLANT MEGAWATT/MINUTE RATE LIMITS WHICH MAY BE AVAILABLE FROM ALGORITHMS a - MAXIMUM NORMAL LOADING RATE b - MAXIMUM EMERGENCY LOADING RATE c - MAXIMUM NORMAL UNLOADING RATE d - MAXIMUM EMERGENCY UNLOADING RATE e - MINIMUM LOADING OR UNLOADING RATE
T (OPTIOAL EVERY 2 SECONDS)	THE NUMBER OF DASHPOTS BYPASSED IN THE PLANT

MESSAGE CONTENTS - PPGC MESSAGE (CONT.)

IDENTIFIER	MEANING
U (OPTIONAL)	THE STATUS OF EACH GENERATOR a - GEN 1, b - GEN 2, ECT. 0 - GEN OFF LINE AND UNAVAILABLE 1 - GEN OFF LINE AND AVAILABLE 2 - GEN ON LINE RUNNING 3 - GEN ON LINE AND CONDENSING
V (OPTIOAL EVERY 2 SECONDS)	THE MEGAWATT OUTPUT OF EACH GENERATOR a - GEN 1, b - GEN 2, ETC.

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WATERTOWN AGC

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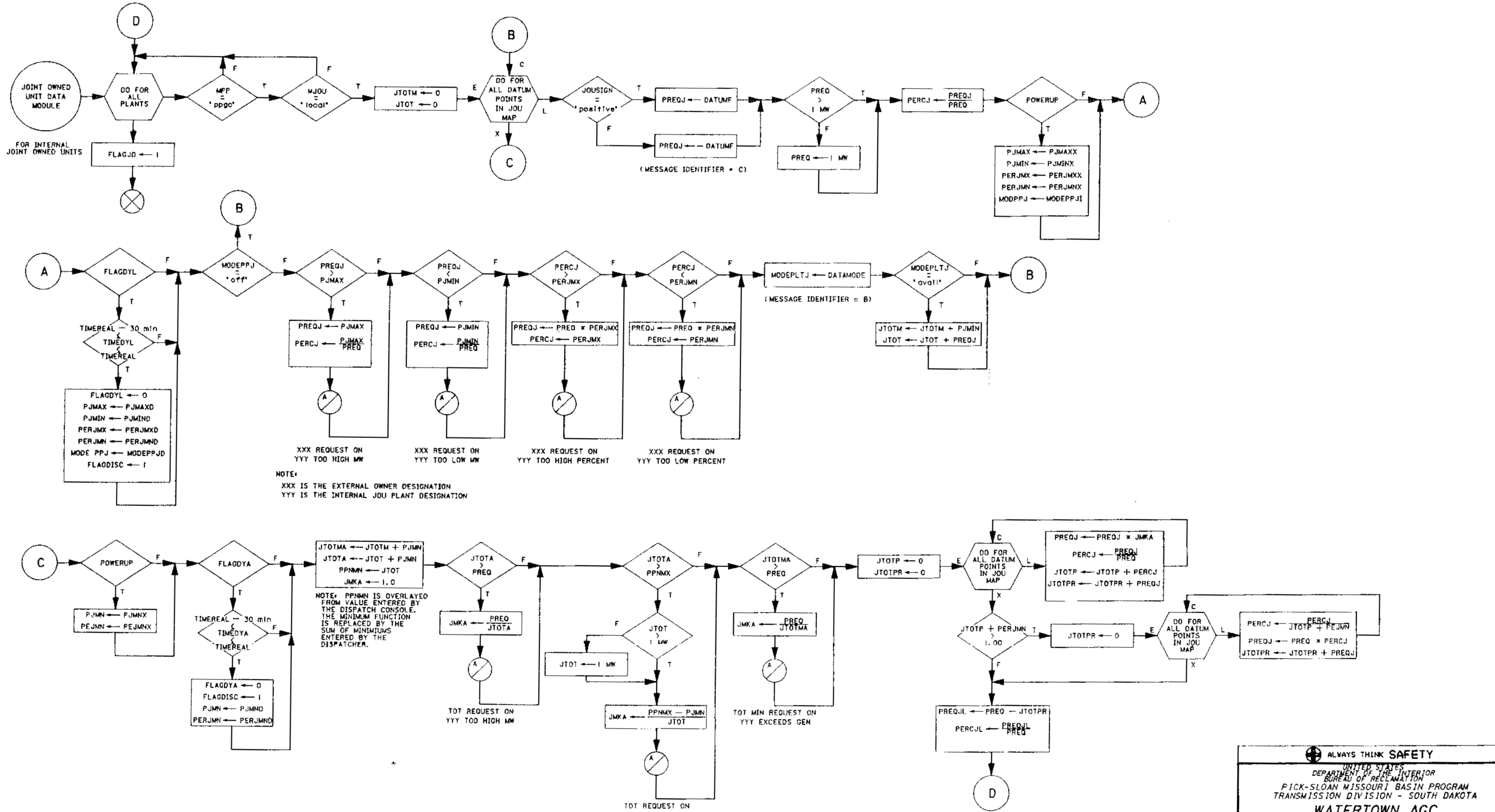
DRAWN ________ SUBMITTED ________
CHECKED ________ APPROVED ________
CHIEF, ELECTRICAL BRANCH
DENVER, COLORADO JUNE 1, 1979 466-EP-30

Figure 20.—Powerplant communications link.



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WATERTOWN AGC

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DRAWN ________ SUBMITTED ________
CHECKED ________ APPROVED ________
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Figure 21.—Joint-owned unit data module.

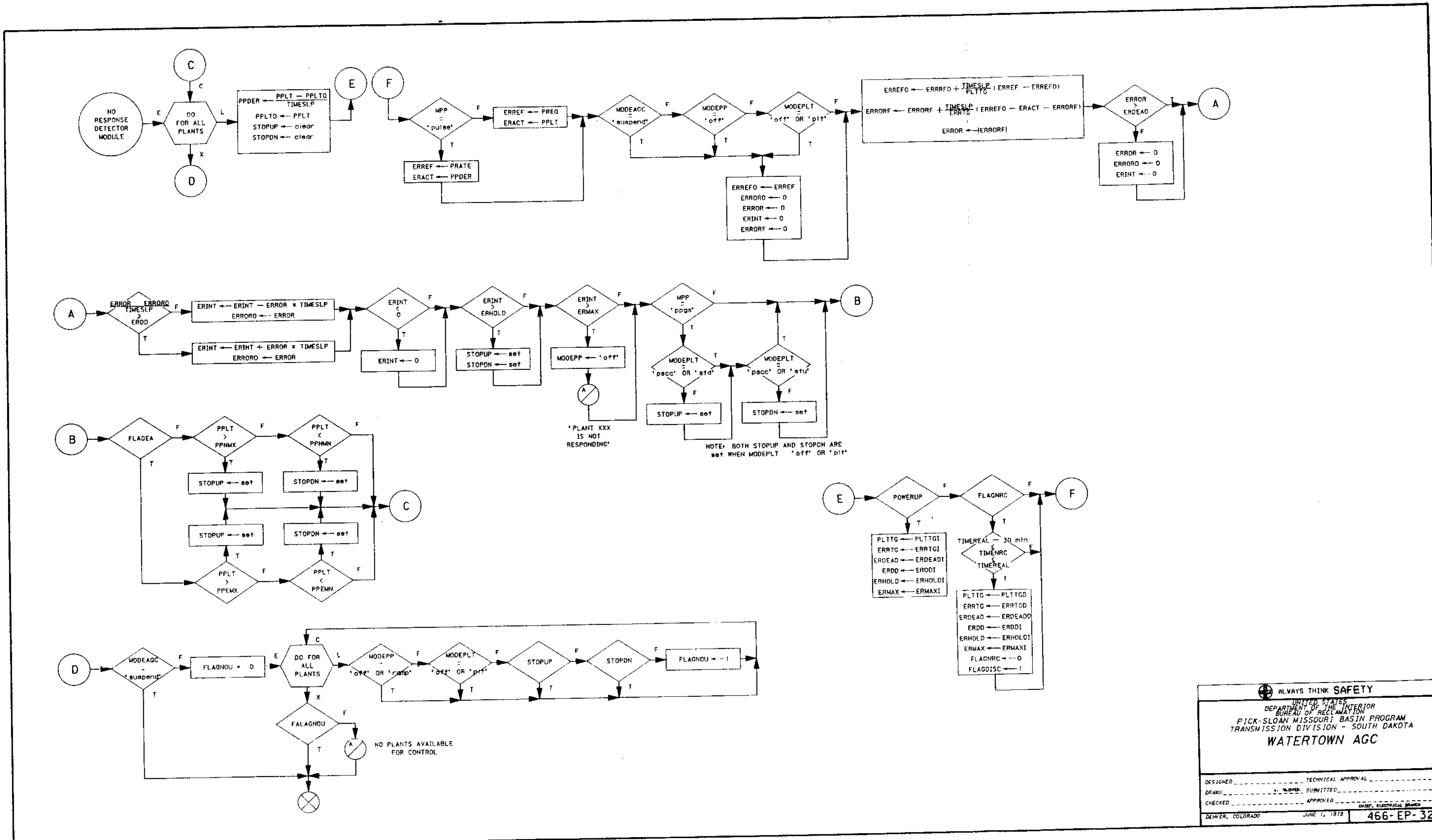


Figure 22.—No-response detector module.

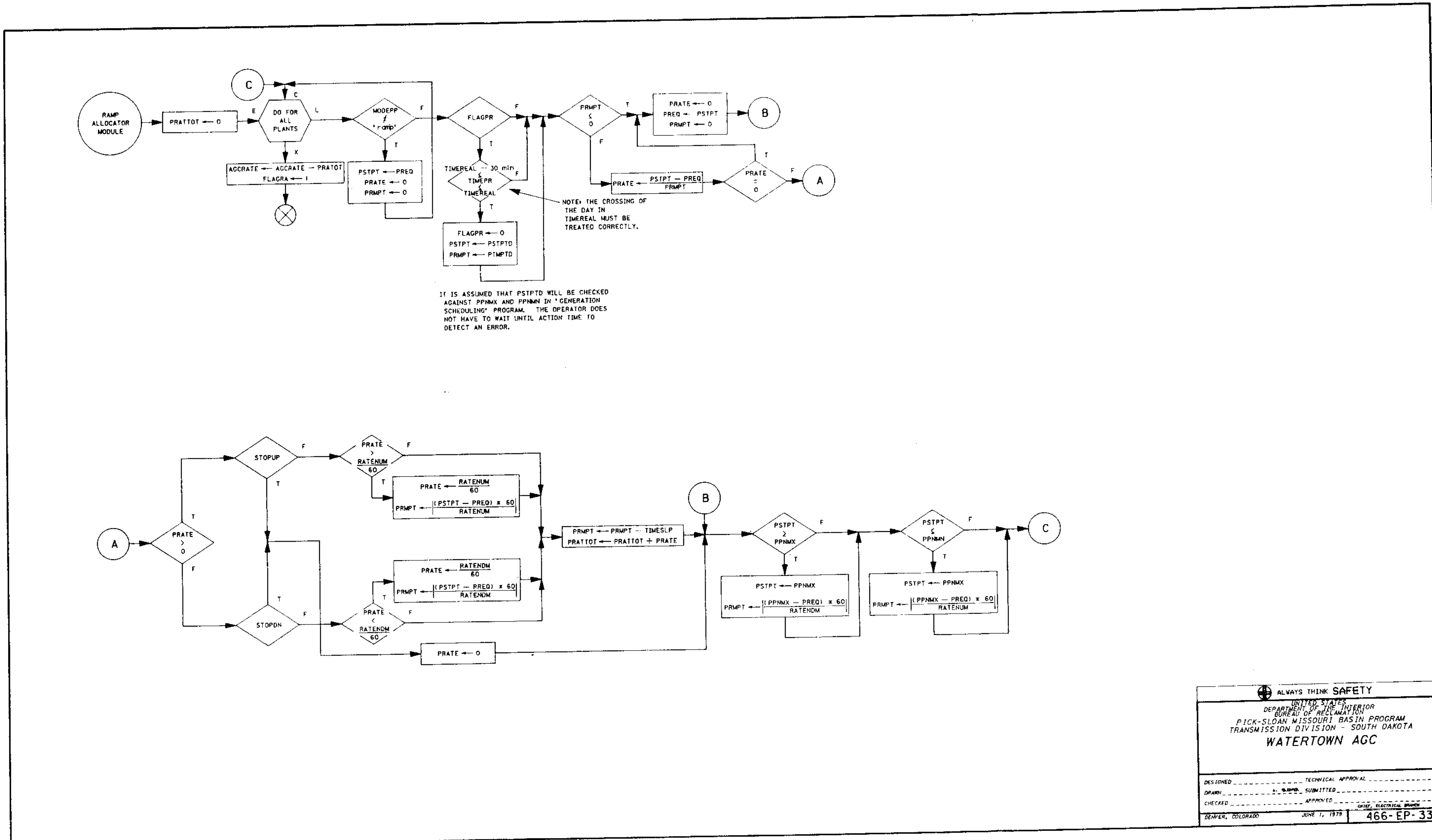


Figure 23.—Ramp allocator module.

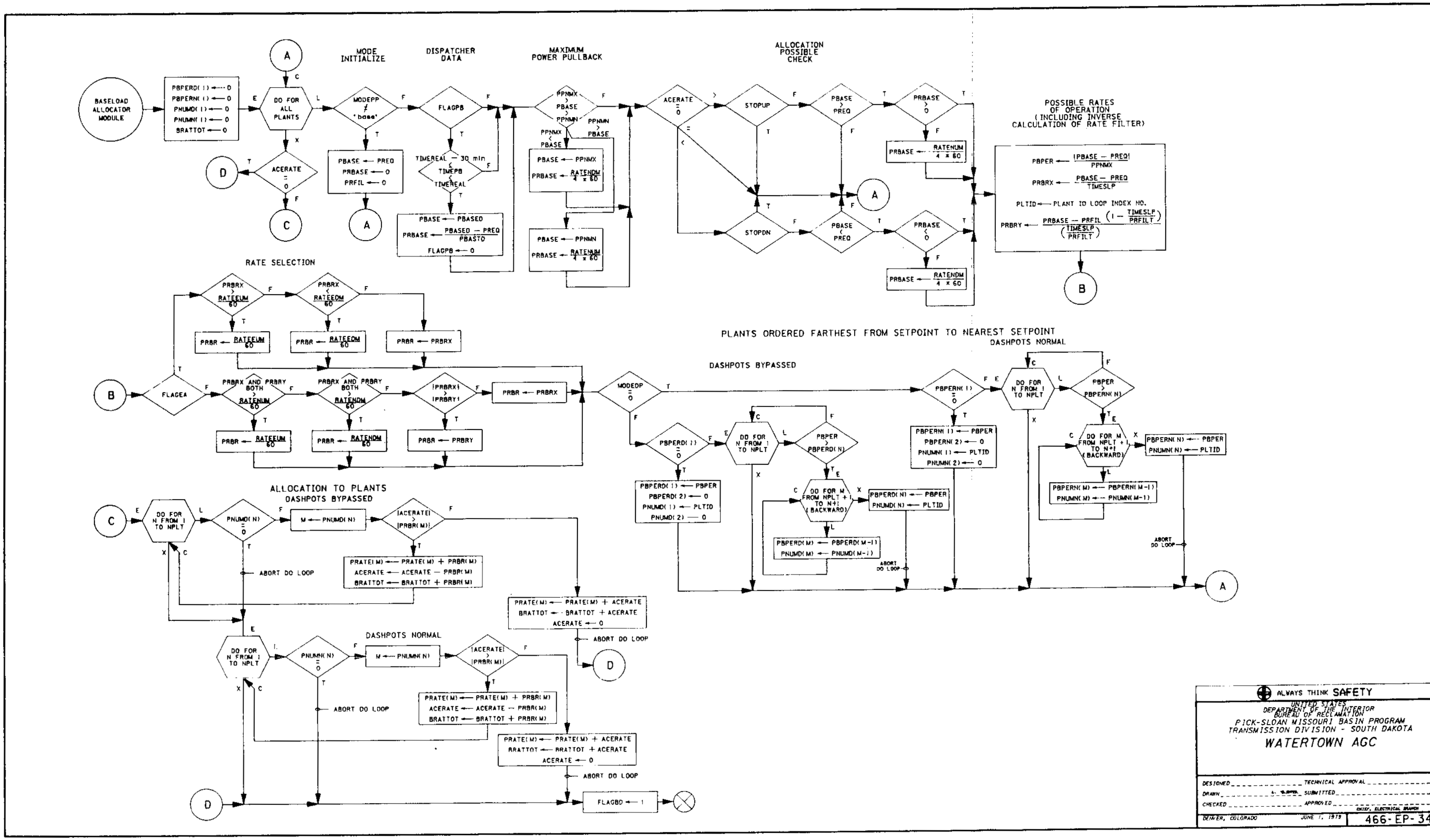


Figure 24.—Baseload allocator module.

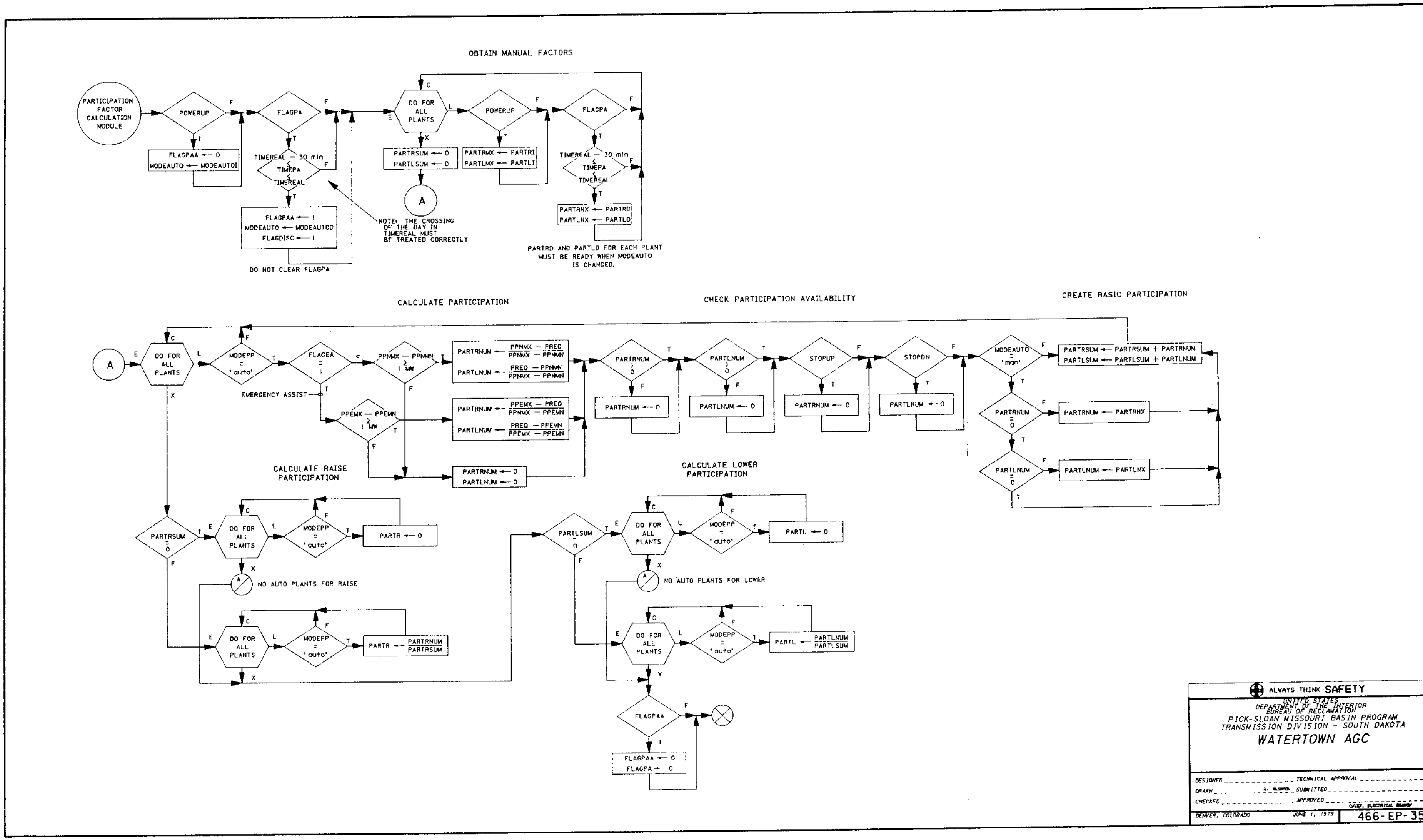


Figure 25.—Participation factor calculation module.

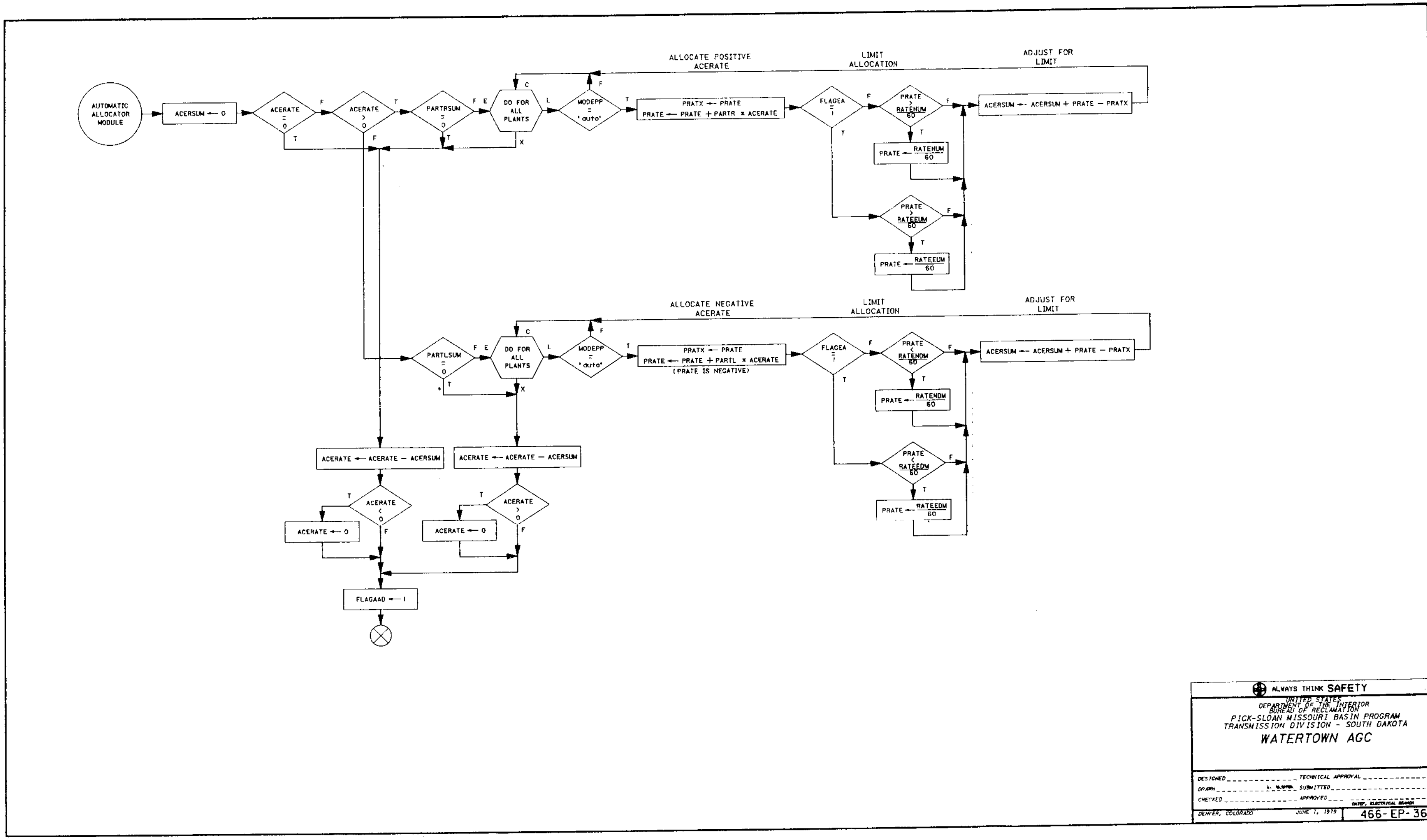


Figure 26.—Automatic allocator module.

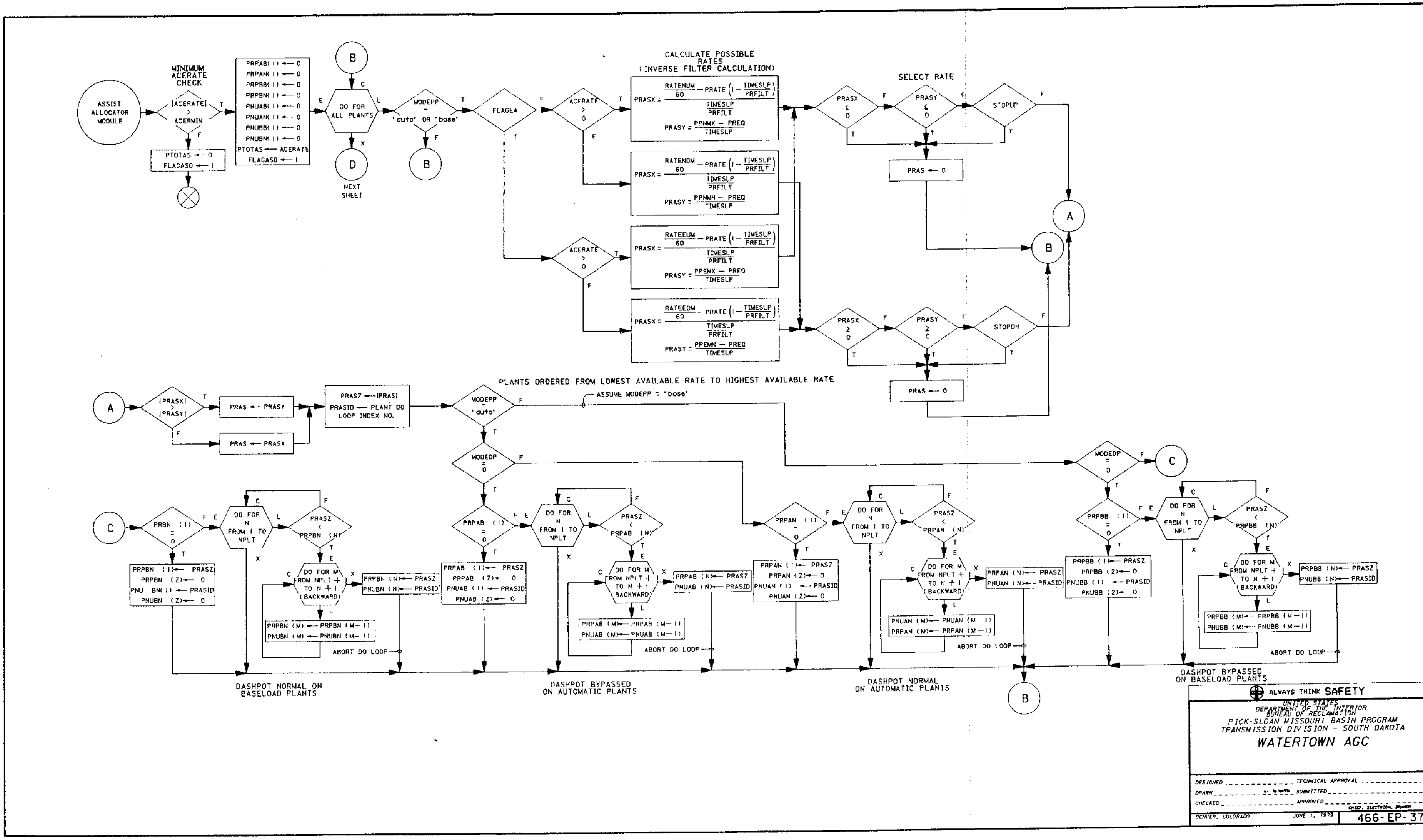


Figure 27.—Assist allocator module (Sheet 1 of 2).

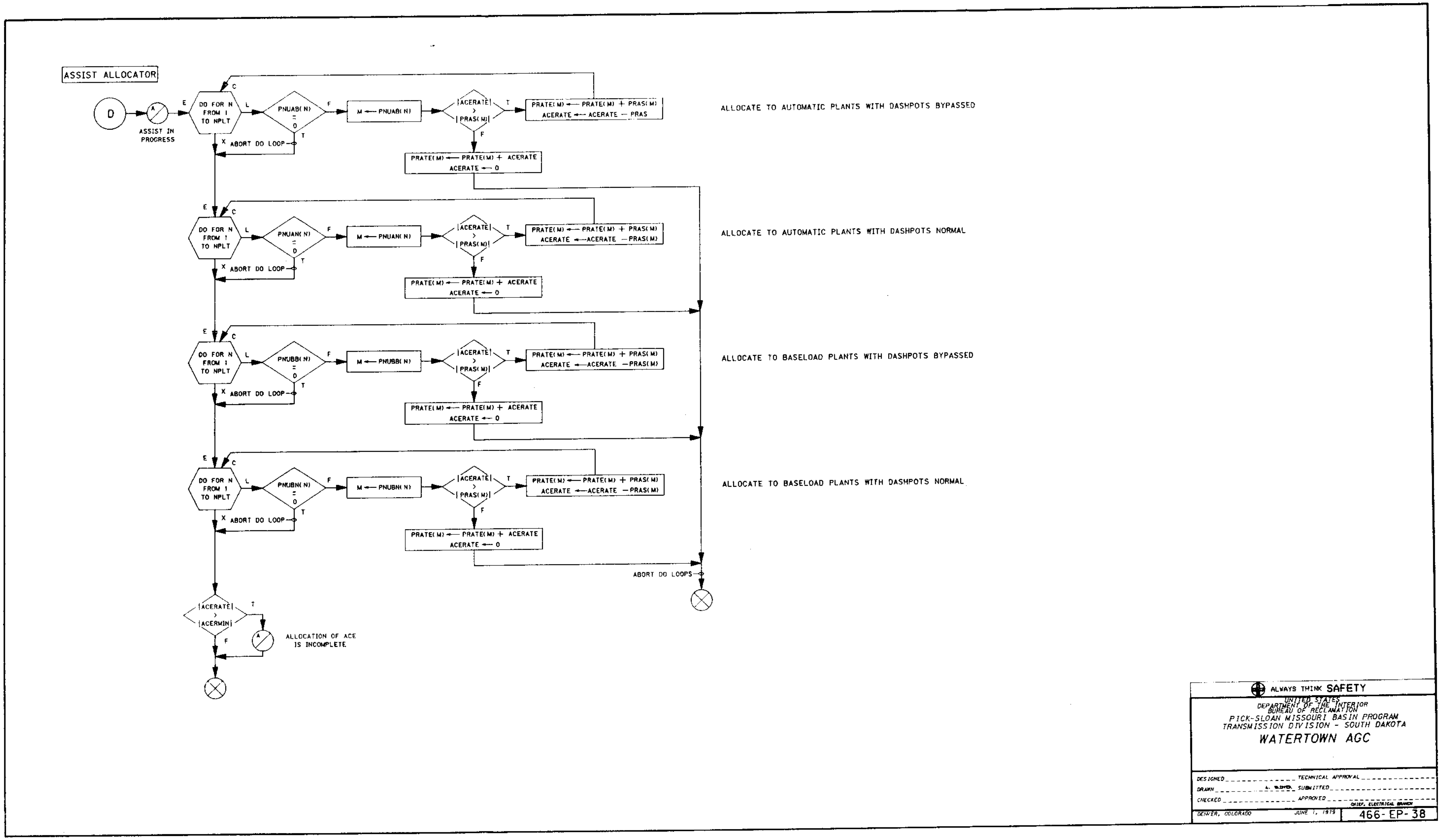


Figure 27.—Assist allocator module (Sheet 2 of 2).

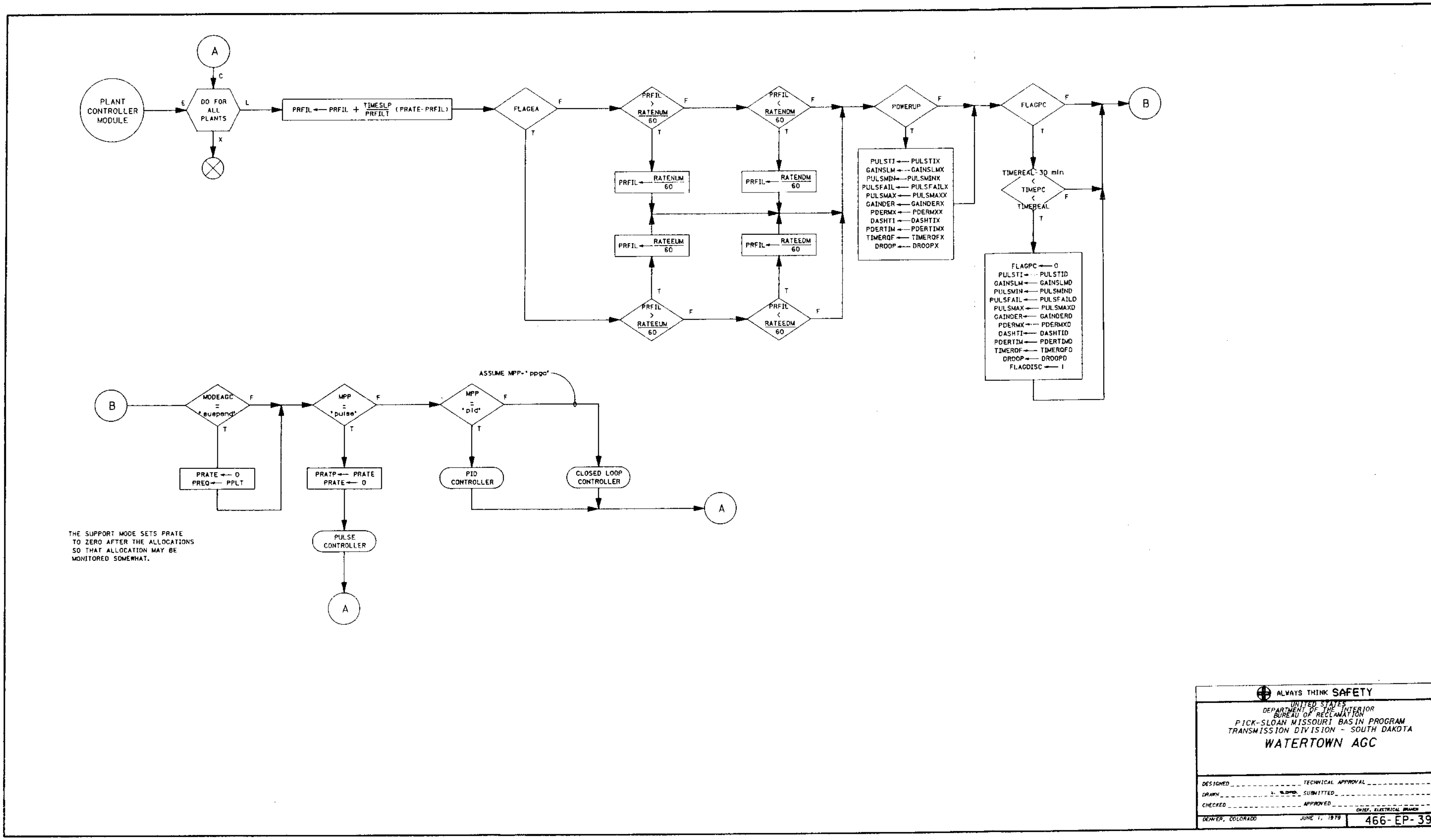


Figure 28.—Plant control module (Sheet 1 of 4).

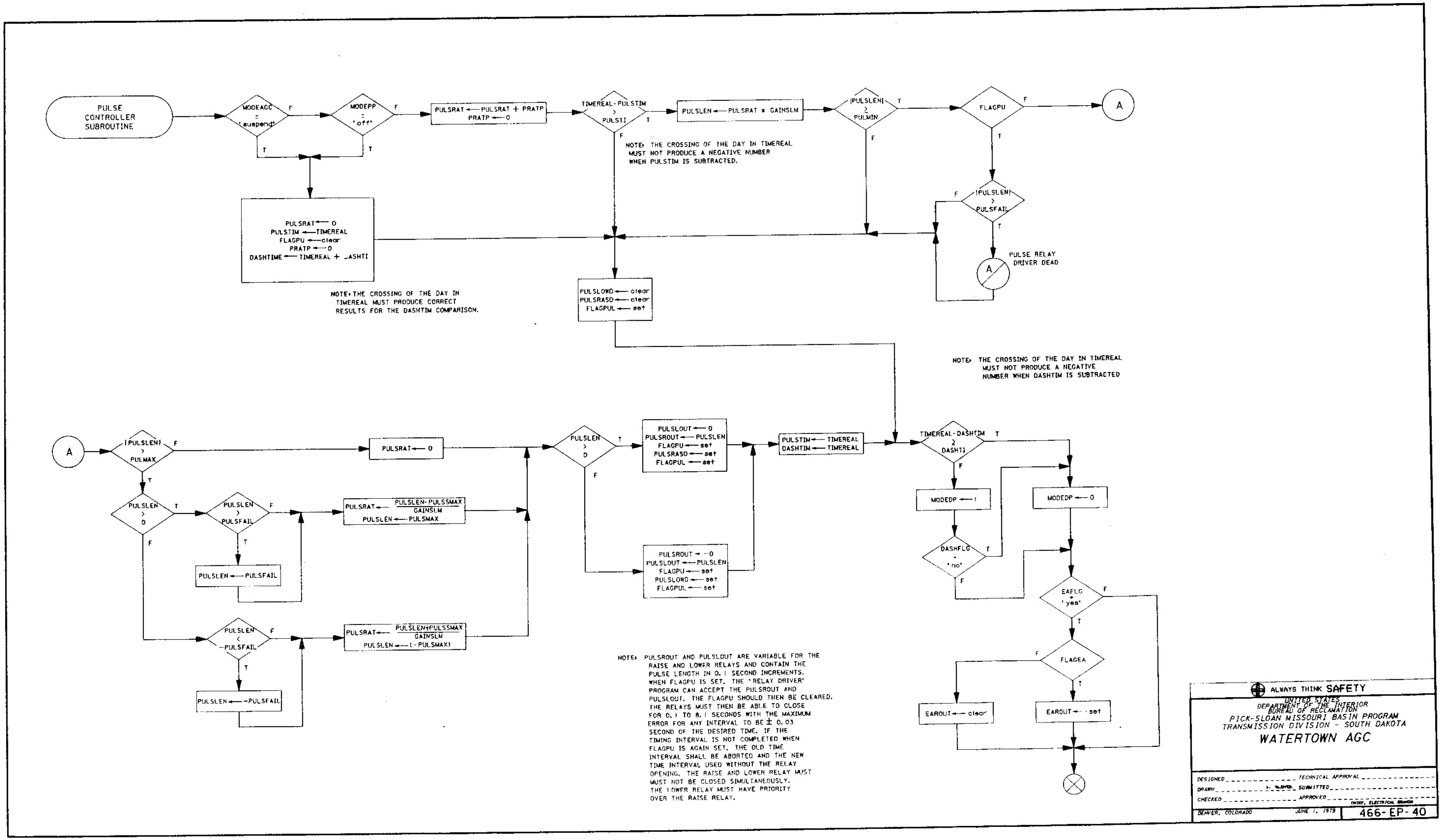


Figure 28.—Plant control module (Sheet 2 of 4).

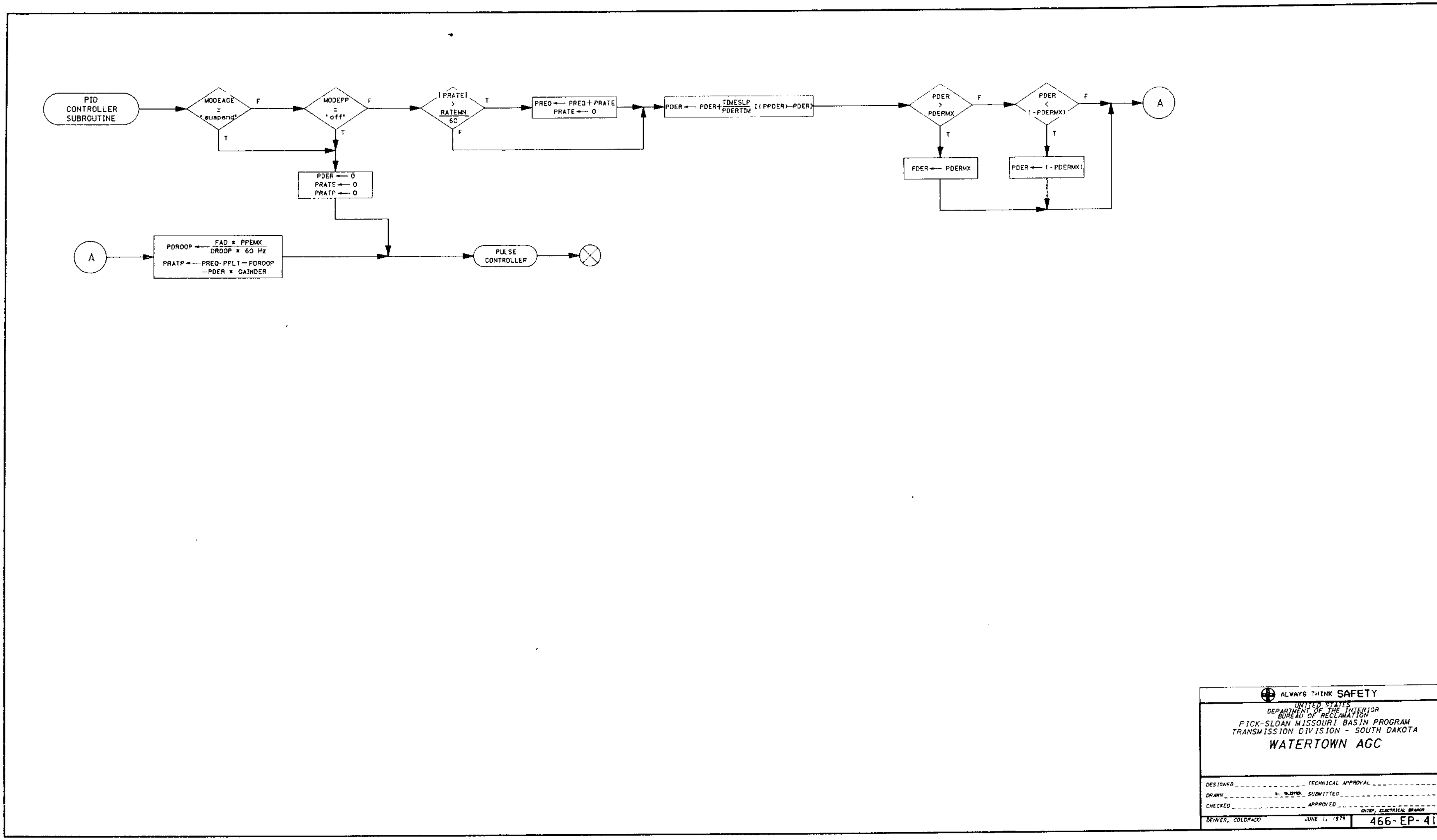


Figure 28.—Plant control module (Sheet 3 of 4).

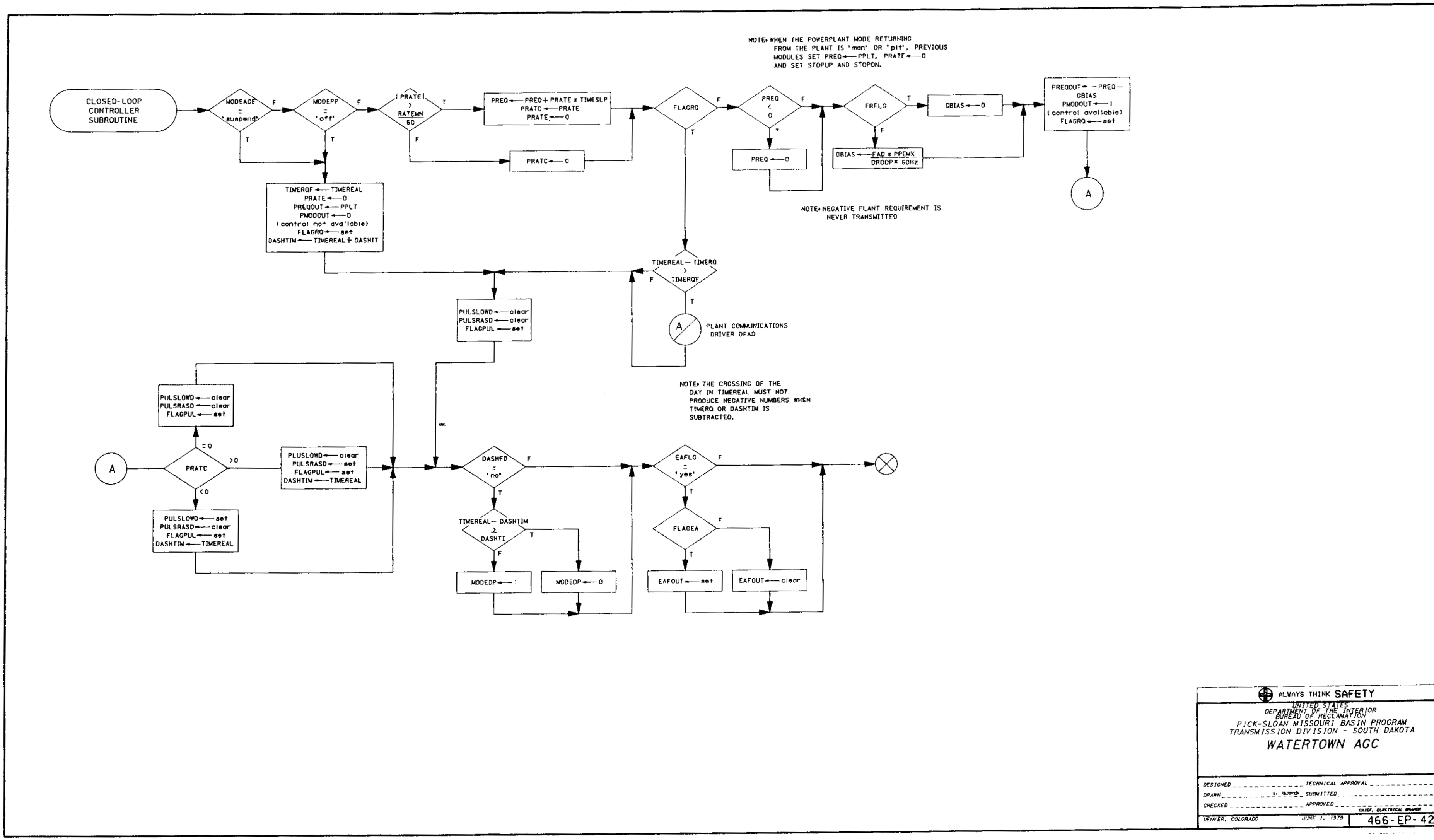


Figure 28.—Plant control module (Sheet 4 of 4).

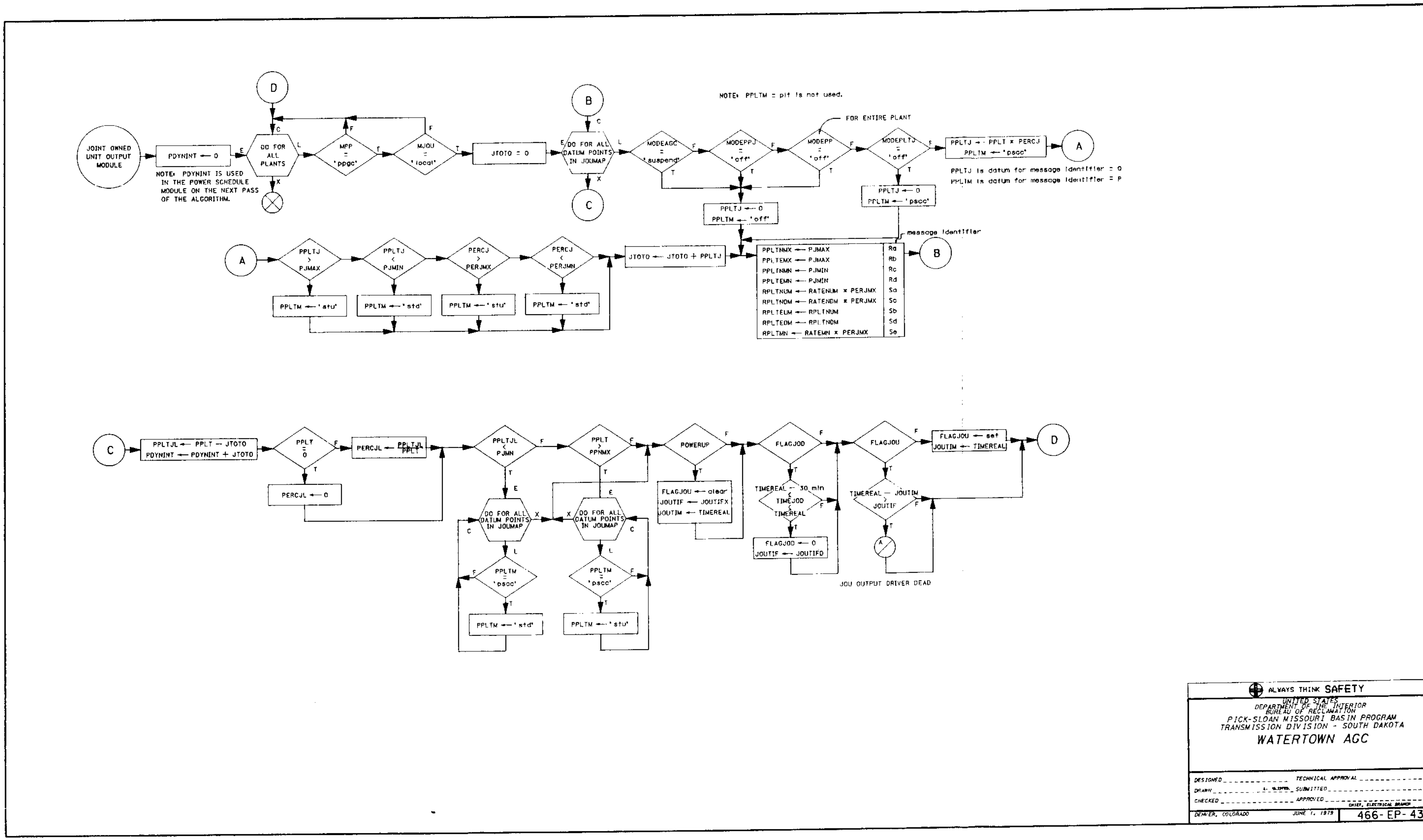
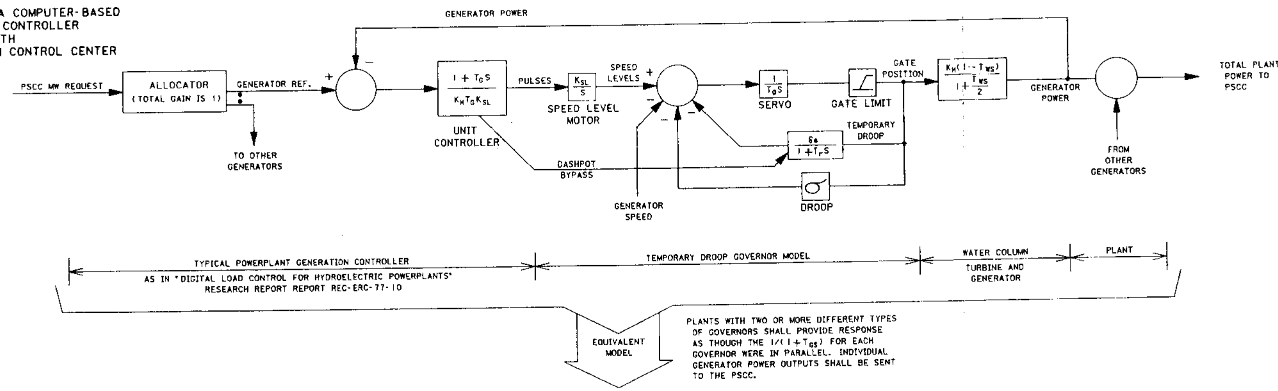


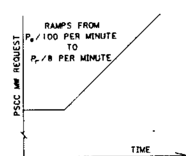
Figure 29.—Joint-owned unit output module.

RESPONSE SPECIFICATIONS FOR A COMPUTER-BASED POWERPLANT GENERATION CONTROLLER COORDINATED WITH THE WATERTOWN POWER SYSTEM CONTROL CENTER

CLASSICAL MODEL OF A HYDROELECTRIC GOVERNOR AND GENERATOR



PLANTS WITH TWO OR MORE DIFFERENT TYPES OF GOVERNORS SHALL PROVIDE RESPONSE AS THOUGH THE $1/(1+T_{GS})$ FOR EACH GOVERNOR WERE IN PARALLEL. INDIVIDUAL GENERATOR POWER OUTPUTS SHALL BE SENT TO THE PSCC.



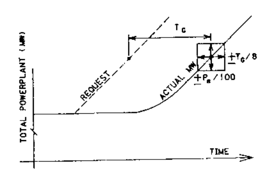
RAMPS USED FOR DEMONSTRATION OF RESPONSE SHALL BE TRIANGULAR FUNCTION SIGNALS WITH A PEAK TO PEAK AMPLITUDE OF Pr/3. FOR RAMPS SLOWER THAN Ps/50 PER MINUTE, THE PEAK TO PEAK AMPLITUDE SHALL ALSO BE Ps/25.

$$\text{PSCC MW REQUEST} \longrightarrow \boxed{\frac{1}{1+T_G S}} \longrightarrow \text{TO PSCC}$$

ALL OTHER FACTORS OF S SHALL BE LESS THAN 8 TIMES SMALLER THAN T_G

$$T_G \simeq \frac{\delta T_r}{\sigma} + T_r$$

IF FREQUENCY OF THE SYSTEM DEVIATES AND CAUSES A CHANGE OF PLANT POWER OF MORE THAN Pr/100 DUE TO GOVERNOR DROOP, THEN THE PSCC MW REQUEST SHOULD BE MODIFIED TO ALLOW THE PROPER DROOP. THE EFFECT OF DROOP ON THE PSCC MW REQUEST SHOULD BE RESET OR WASHED-OUT ON A 10-MINUTE TIME CONSTANT.



THE RESPONSE SHALL BE WITHIN THE TOLERANCES INSIDE THE BOX. IF THE RESPONSE MOVES OUTSIDE THE BOX, A STOP ALLOCATION SIGNAL SHALL BE SENT TO THE PSCC WITHIN T_G SECONDS OR 30 SECONDS, WHICHEVER IS LONGER.

GOALS OF RESPONSE

1. THE DOMINANT LAPLACE POLES SHALL BE REDUCED TO ONE REAL POLE TO ALLOW INCREASE GAIN IN THE OVERALL AGC CONTROLLER. THIS SHALL BE DONE WITHOUT MODIFICATION OF EXISTING GENERATING EQUIPMENT IF POSSIBLE.
2. THE PLANT SHALL RESPOND TO CHANGES IN THE PSCC MW REQUEST AS SMALL AS Ps/100 IN EITHER DIRECTION. NON-LINEARITIES AND BACKLASH OF THE SPEED LEVEL MOTOR AND GOVERNOR SHALL BE COMPENSATED AS MUCH AS POSSIBLE. THIS INSURES THAT CORRECTIONS FOR ACE WILL ALWAYS BE INITIALIZED.
3. NO ADDITIONAL CONSTRAINTS OF RAMPING THE GENERATORS SHALL BE PLACED ON THE RESPONSE BY THE COMPUTER. ONLY THE CONSTRAINTS IMPOSED BY THE GOVERNOR VALVES ENCOUNTERING STOPS (INTERNAL OPERATION OF THE GOVERNOR BECOMMING LIMITED), THE HEATING RATE OF THE STATOR, OR RIVER CHANGE LIMITATIONS SHALL BE A VALID RESPONSE CONSTRAINT. ONLY THE CONSTRAINTS IMPOSED BY THE GOVENOR VALVES ECONTERING STOPS (INTERNAL OPERATION OF THE GOVENOR BECOMING LIMITED), THE HEATING RATE OF THE STATOR, OR RIVER CHANGE LIMITATIONS SHALL BE A VALID RESPONSE CONSTRAINT.

DEFINITION OF SYMBOLS

K_H — THE EFFECTIVE GAIN BETWEEN GATE POSITION AND TURBINE POWER OUTPUT.
K_{SL} — THE EFFECTIVE GAIN OF THE SPEED LEVEL MOTOR.
P_r — THE TOTAL RATED CAPACITY OF ALL GENERATORS ON AGC CONTROL.
P_s — THE RATED CAPACITY OF THE SMALLEST GENERATOR ON AGC CONTROL.
T_g — THE OPEN LOOP GOVERNOR RESPONSE TIME.
T_G — THE DOMINANT GOVERNOR CLOSED-LOOP RESPONSE TIME IN SECONDS. THE TIME IS MEASURED AS THE TIME TO 63 PERCENT OF THE FINAL POWER OUTPUT FOR A STEP INTO THE GOVERNOR SPEED ADJUST.
T_r — THE DASHPOT RECOVERY TIME.
T_w — THE WATER STARTING TIME.
S — LA PLACE VARIABLE (COMPLEX FREQUENCY).
δ — THE TEMPORARY DROOP.
σ — THE PERMANENT DROOP

EXAMPLE

FOR GARRISON POWERPLANT,

$P_r = 400$ MW, $P_s = 40$ MW

$T_G = 31$ SECONDS. (DASHPOTS IN SERVICE)

THE RAMPS WOULD BE FROM 0.4 MW/MIN TO 50 MW/MIN WITH A PEAK-PEAK AMPLITUDE OF 133 MW. FOR RAMPS BELOW 0.08 MW/MIN, THE AMPLITUDE WILL ALSO BE 1

THE TOLERANCE BOX WOULD FOLLOW THE REQUEST BY 31 ± 3.8 SECONDS WITH AN AMPLITUDE ERROR OF 0.4 MW.

EXPLANATION OF RAMPS

THE RANGE OF RAMPS WAS CHOSEN TO DEMONSTF CAPABILITY OF THE CONTROLLER TO FOLLOW THE FLUCTUATIONS OF THE PSCC MW REQUEST DUE TO THE ALLOCATION OF ACE BY THE AGC.

THE SLOW RAMPS DEMONSTRATE THE ABILITY TO CORRECT THE SLOW DRIFTS IN ACE. THE FASTER RAMPS DEMONSTRATE THE ABILITY TO CORRECT FOR LARGE LOAD OR GENERATION CHANGES WITHIN THE SYSTEM. THE AMPLITUDE OF THE RAMPS ARE ALLOWED A VALID DEMONSTRATION WITHOUT EXCEEDING CAPACITY OR ENTERING INTO ROUGH ZONES.

THE LOW AMPLITUDE RAMP DEMONSTRATES THE ABILITY TO OVERCOME BACKLASH.

REFERENCES

Gish, W.B., "DIGITAL LOAD CONTROL FOR HYDROELECTRIC POWERPLANTS", Report REC-ERC-77-10, August 1977.

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Gish, W.B., "AUTOMATIC GENERATION CONTROL-NOTES AND OBSERVATIONS", Report REC-ERC-78-6, October 1978.

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Ramey, D.G. and J.W. Skooglund, "DETAILED HYDROGOVERNOR REPRESENTATION FOR SYSTEM STABILITY STUDIES", PAS-89, NO. 1, Jan. 1970, pp 106-112.

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WATERTOWN AGC

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CHECKED	APPROVED — CHIEF, ELECTRICAL BRANCH
DENVER, COLORADO JUNE 1, 1979	466-EP-44

Figure 30.—Plant response specifications.

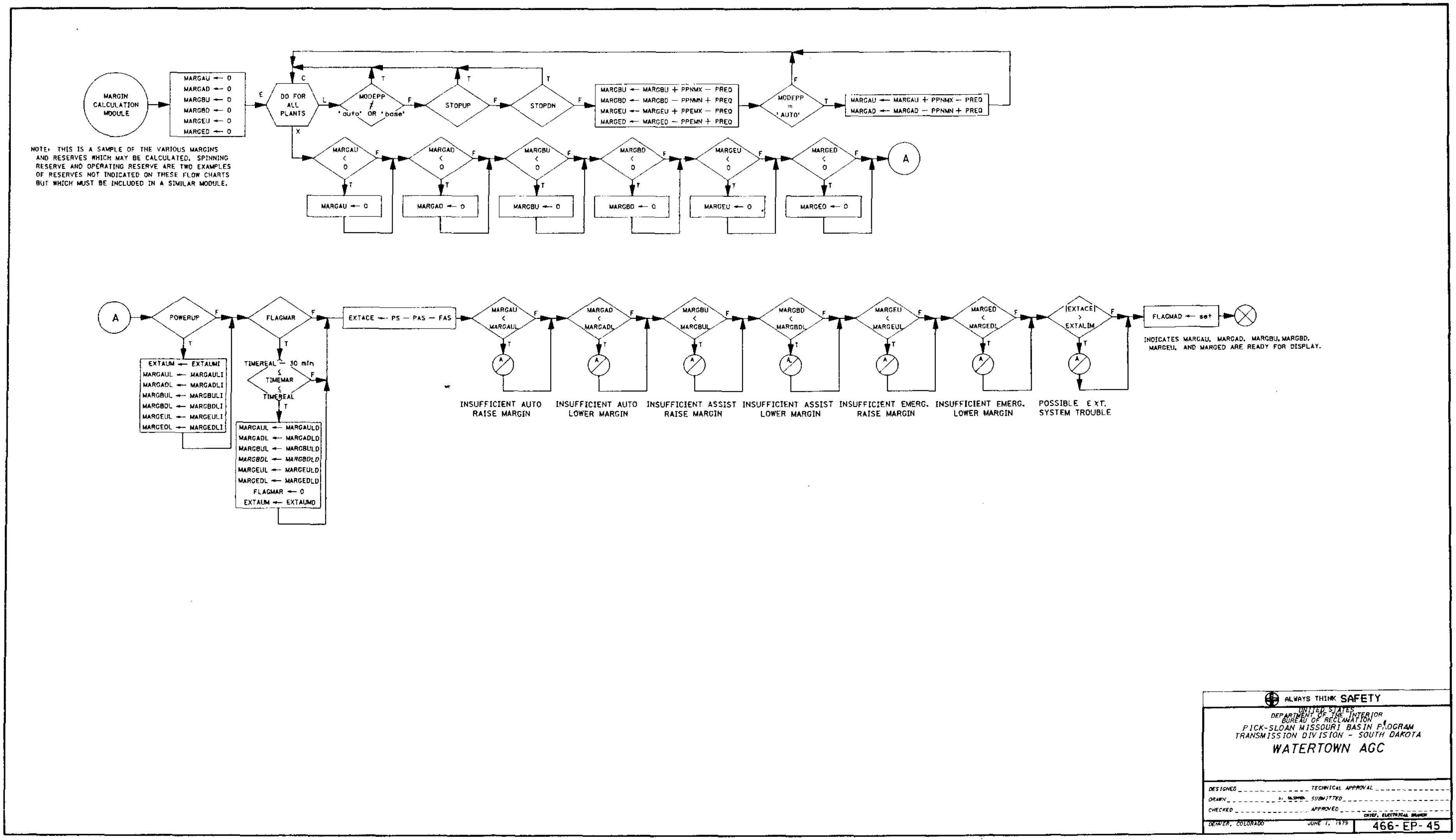


Figure 31.—Margins calculation module.

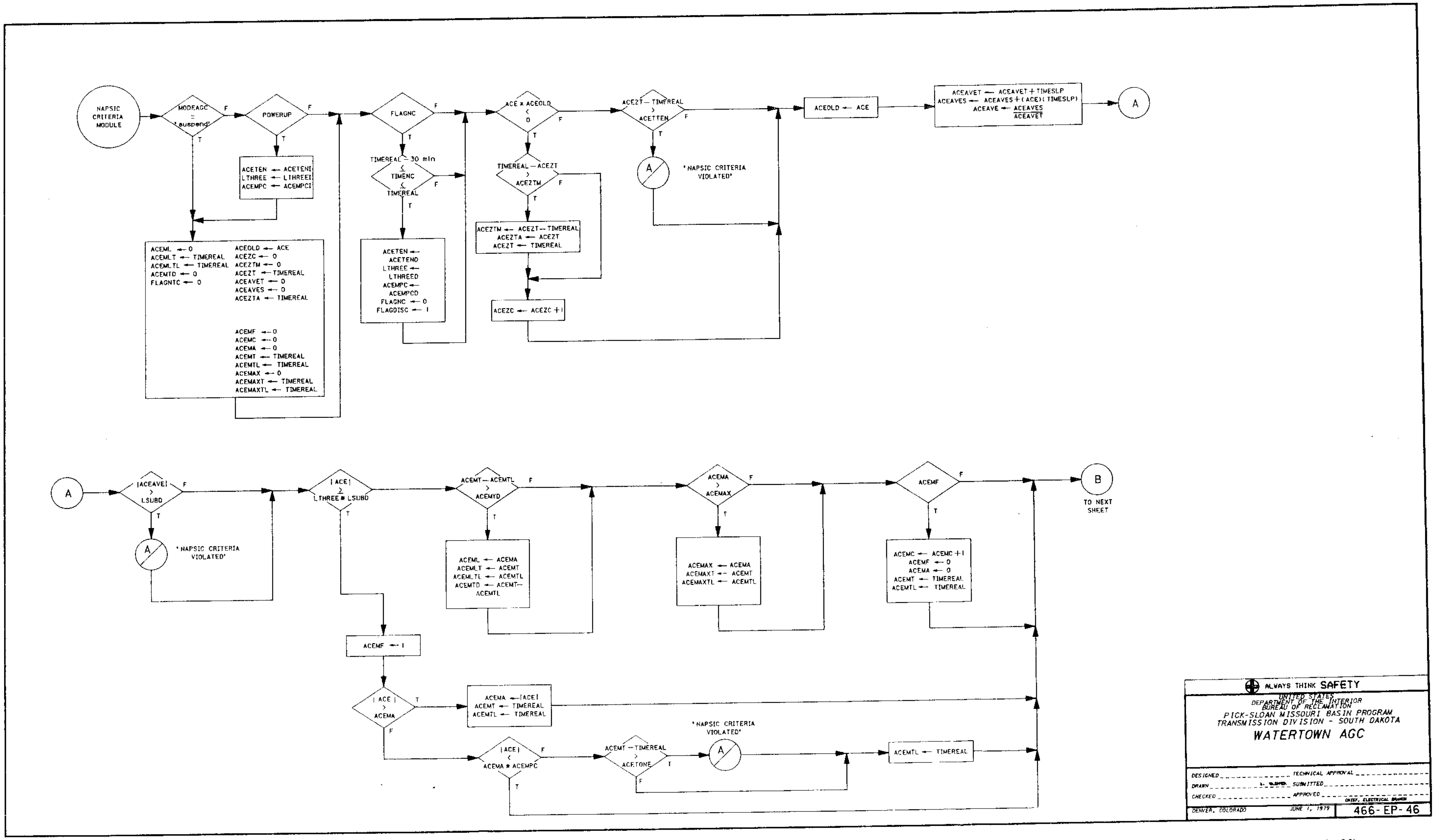


Figure 32.—NAPSIC criteria module (Sheet 1 of 2).

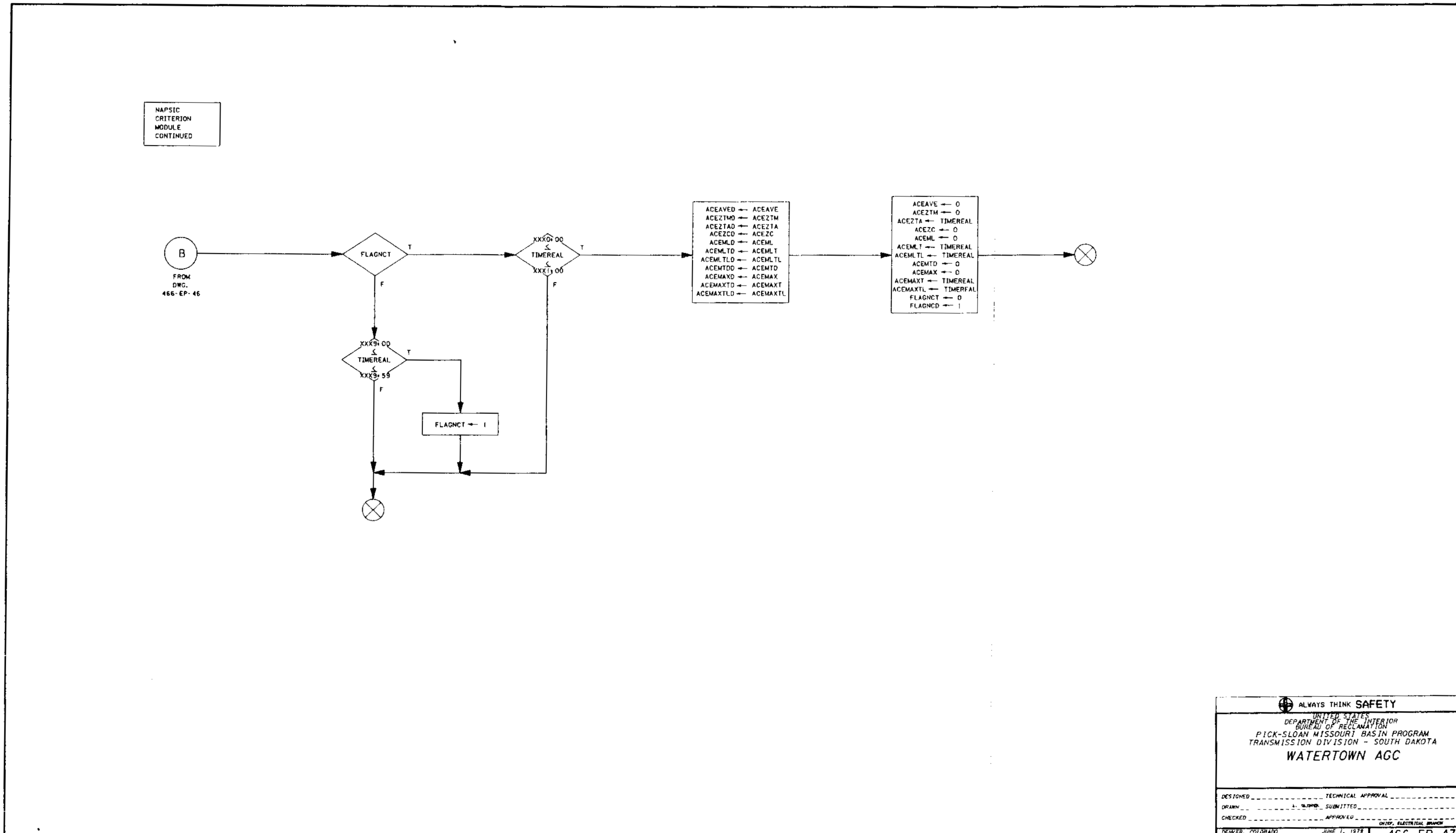


Figure 32.—NAPSIC criteria module (Sheet 2 of 2).

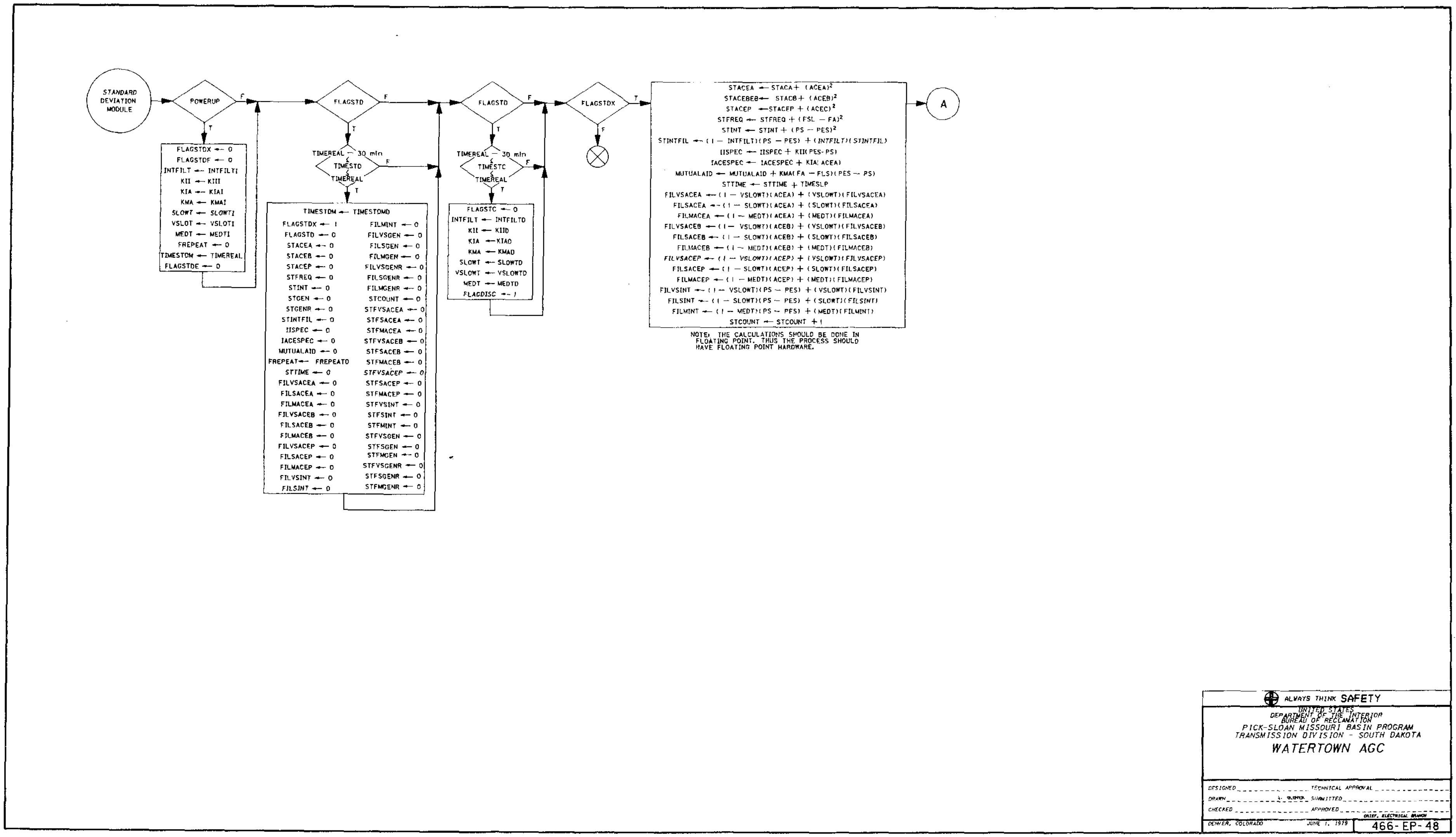


Figure 33.—Standard deviation module (Sheet 1 of 2).

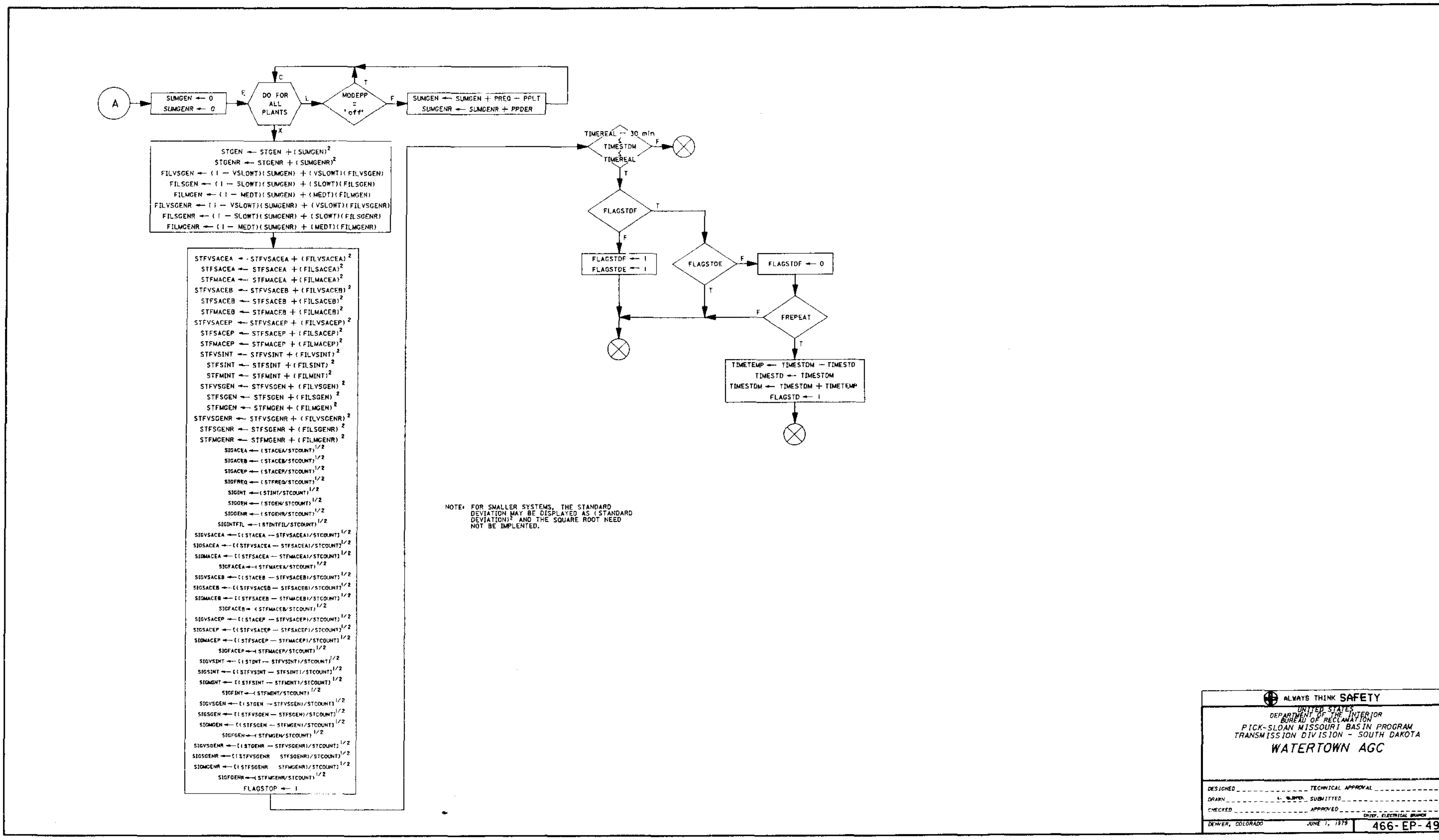


Figure 33.—Standard deviation module (Sheet 2 of 2).

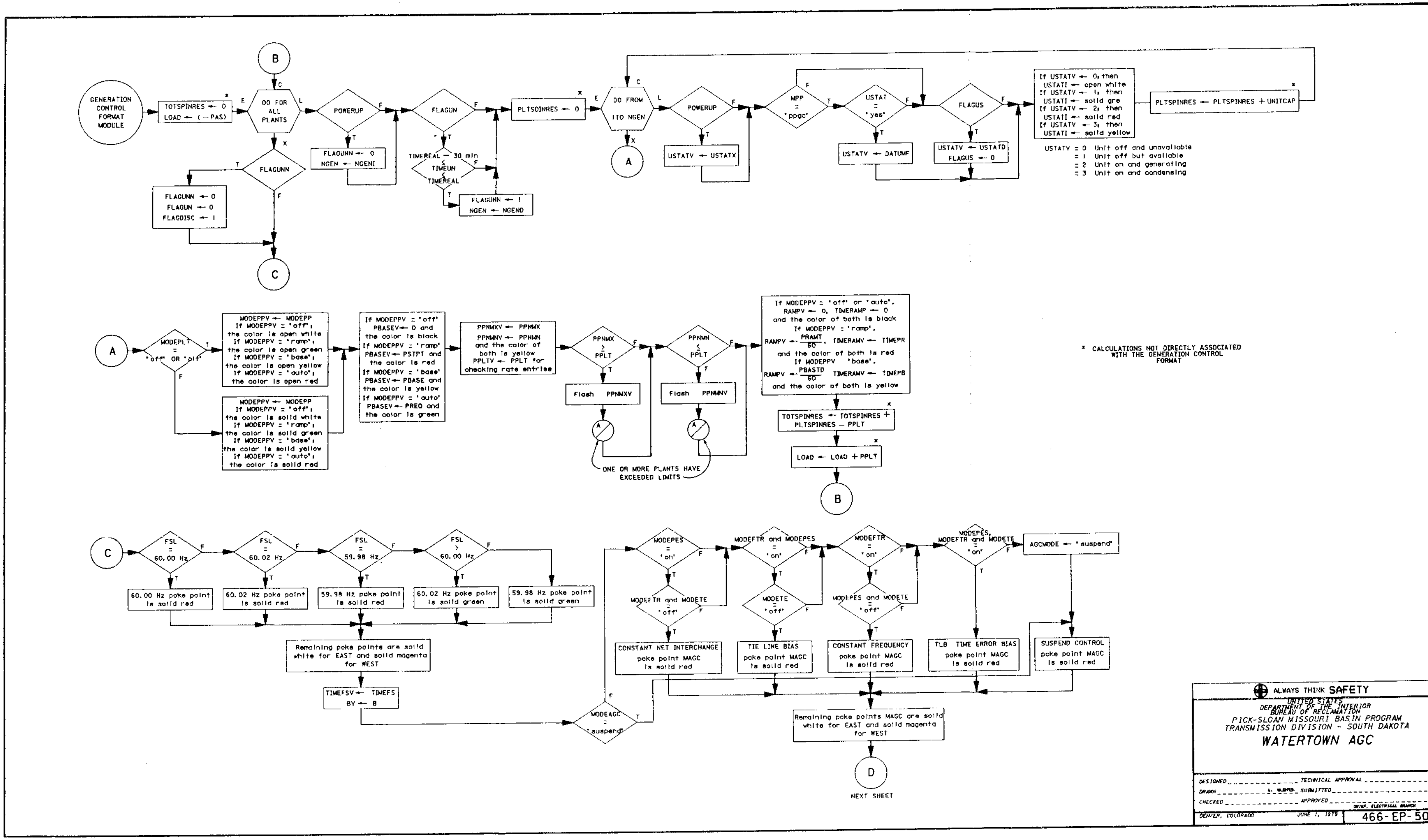


Figure 34.—Generation control format module (Sheet 1 of 3).

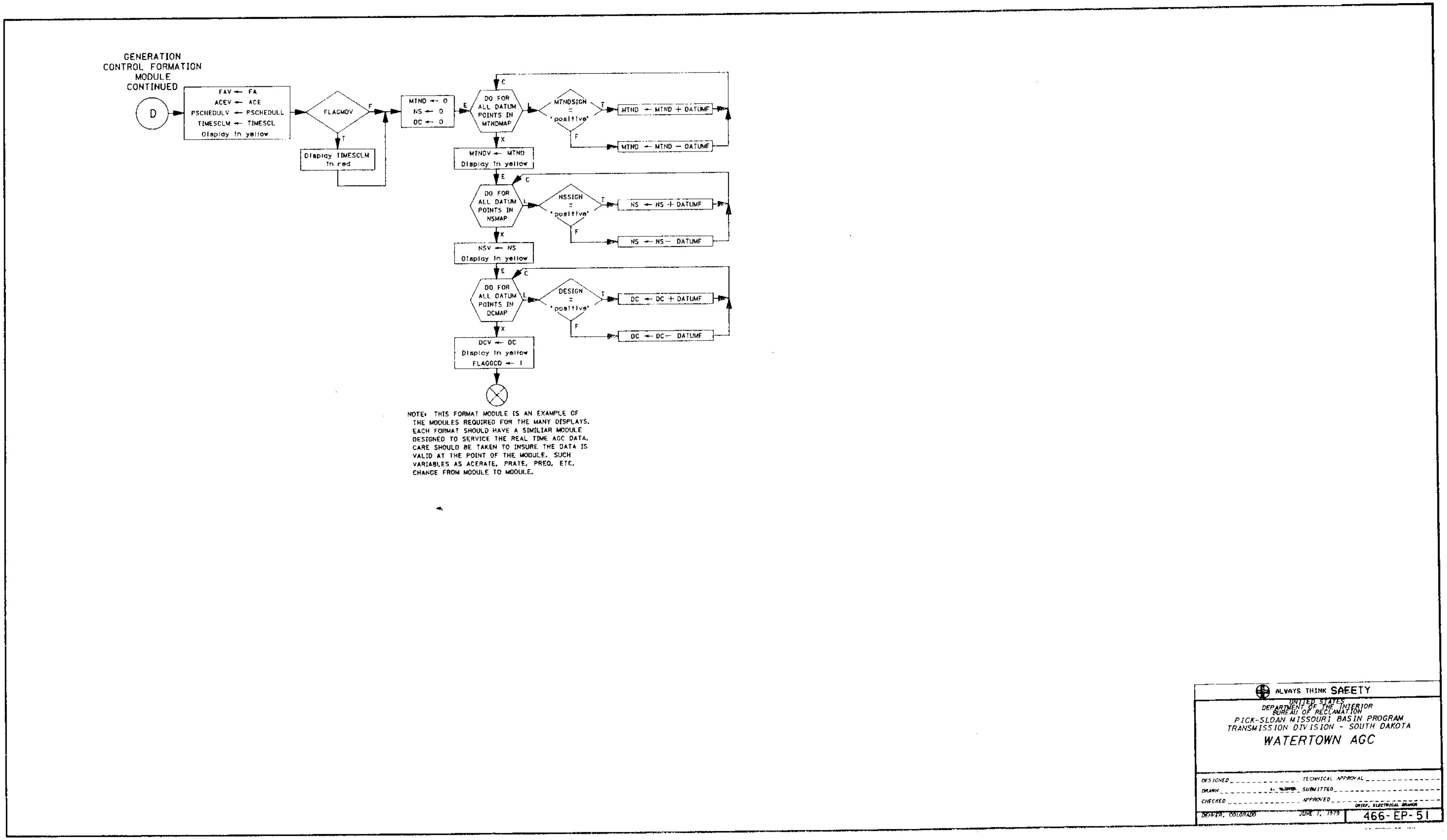
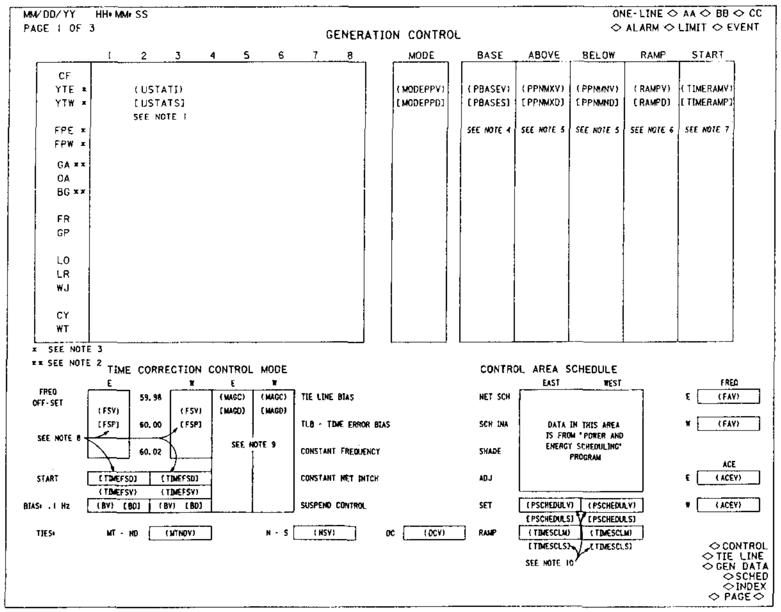


Figure 34.—Generation control format module (Sheet 2 of 3).

(VARIABLE) = THE DISPLAYED VARIABLE
[VARIABLE] = THE VARIABLE ENTERED BY THE DISPATCHER

EAST AND WEST DATA ARE SUPPLIED BY DIFFERENT DATA BASES USING VARIABLES BY THE SAME NAMES.



NOTES

1. USTATI is determined by the 'AGC Algorithm'. USTATS is used by the display input control program. Each point must be checked for USTAT. If it is 'no', the USTATS maybe translated from the type of symbol and color entered to USTATD numbers. An open white symbol in USTATS means USTATD ← 0, a solid green USTATS means USTATD ← 1, a solid red USTATS means USTATD ← 2, a solid yellow USTATS means USTATD ← 3. If USTAT = 'yes', then the MODEDATA for that DATUMF point must be changed to 'man' and the value of USTATD above must be placed into DATUMF as the entry. Also, set the alarm 'ONE OR MORE AGC DATA CHANNELS HAS CHANGED MODE' and blink the DATUMF value in 'yellow' until the alarm is acknowledged.

2. If MPP = 'pulse' or 'pcd', or if USTAT = 'no', PNMXF = 'no' and PNMNF = 'no', then the color or the plant label should be magenta. If USTAT, PNMXF, or PNMNF= 'yes and the MODEDATA' for any of the DATUMF is 'man', 'off', or 'hold', the color of the plant label should be green. If USTAT, PNMXF, and PNMNF = 'yes' and all MODEDATA for the generators are 'on', 'pri', or 'alt', then the plant label should be colored red.

3. The east and the west part of the powerplants which may have generation either east or west are treated as separate powerplants. However, the USTATS of a generator east having a non-zero value must force the west USTATS to zero. This should be done in the format display output program.

4. PBASES must be sorted into the proper variable depending on MODEPPV. When MODEPPV = 'off', PBASES is illegal. When MODEPPV = 'ramp', PSTPTD ← PBASES. When MODEPPV = 'base', PBASED ← PBASES. When MODEPPV = 'auto', PBASES is illegal.
   a. If TIMERAMP and RAMPD have not been entered after PBASES and before the ENTER is pushed; When MODEPPV = 'RAMP', TIMEPR ← REALTIME, FLAGPR ← set and RAMPD ← 10 (See Note 6). When MODEPPV = 'BASE', TIMEPB ← REALTIME, FLAGPB ← set and RAMPD ← 10 (See Note 6).
   b. If TIMERAMP has not been entered after PBASES and before ENTER is pushed but RAMPV has been entered; When MODEPPV = 'ramp', TIMEPR ← REALTIME, FLAGPR ← set and RAMPD is treated as note 6. When MODEPPV = 'base', TIMEPB ← REALTIME, FLAGPB ← set and RAMPD is treated as note 6.
   c. If RAMPD has not been entered after PBASES and before ENTER is pushed, but TIMERAMP has been entered; When MODEPPV = 'ramp', RAMPD ← 10 (See Note 6), TIMEPR ← TIMERAMP and FLAGPR ← set. When MODEPPV = 'BASE', RAMPD ← 10 (See Note 6), TIMEPB ← TIMERAMP and FLAGPB ← set.
   d. If PPNMXV > PBASES > PPNMNV, then the entry should be declared illegal.

5. If MPP = 'ppgc' and PNMXF = 'yes', then an entry into PPNMXD will cause the value to be in DATUMF. MODEDATA will be set to 'man', DATUMF will blink yellow and an alarm will be set (See Note 1). Also, the plant labels will change color as in Note 2. If MPP = 'ppgc' and PNMX = 'no' or if MPP ≠ 'ppgc', then PPNMXD ← value, TIMEPP ← TIMEREAL and FLAGPP ← set. The identical concept applies to PPNMNF, and PPNMND.

6. If MODEPPV = 'off' or 'auto', RAMPD entries are illegal. If MODEPPV = 'ramp', then RAMPD ← entry; If PBASES − PPLTV ≥ 0, PRMPTD ← PRMPD * 60; If PBASES − PPLTV < 0, PRMPTD ← −RAMPD * 60; Further, if RATENMXV ≥ $\frac{\text{PBASES} - \text{PPLTV}}{\text{RAMPD}}$ ≥ RATENMNV then the entry shall be excepted. Otherwise the entry should be declared illegal. If MODEPPV = 'base', then RAMPD ← entry; If PBASES − PPLTV ≥ 0, PBASTD ← RAMPD * 60; If PBASES − PPLTV < 0, PBASTD ← −RAMPD * 60; Further the test for rate limits above apply. Finally if PRMPTD or PBASTD are loaded and executed before TIMERAMP is loaded then; TIMEPR ← TIMEREAL, FLAGPR ← set when MODEPP = 'ramp' and TIMEPB ← TIMEREAL, FLAGPB ← set when MODEPP = 'base'

7. If MODEPPV ←'off' or 'auto', TIMERAMP entries are illegal. If MODEPPV ←'ramp' then TIMEPR ← TIMERAMP and FLAGPR ← SET. If MODEPPV ← 'base' then TIMEPB ← TIMERAMP and FLAGPB ← set.

8. When FSP pokepoint is selected, FS ←59.98 Hz, or 60.02 Hz depending on which pokepoint is addressed. If ENTER key is depressed before TIMEFSD is entered, then TIMEFS ← TIMEREAL and FLAGFS← set. If TIMEFSD is entered before the ENTER key is pressed, then TIMEFS ← TIMEFSD and FLAGFS ← set.

9. When the pokepoint MAGD is selected,
   If the point is TIELINE BIAS, MODEPES ← 'on', MODEFR ← 'on', MODETE ← 'off', and MODEAGE ← 'on'.
   If the point is TLB - TIME ERROR BIAS, MODEPES ← 'on', MODEFR ← 'on', MODETE ← 'on', and MODEAGC ← 'on'.
   If the point is CONSTANT FREQUENCY, MODEPES ← 'off', MODEFR ← 'on', MODETE ← 'off', and MODEAGC ← 'on'.
   If the point is CONSTANT NET INTCH, MODEPES ← 'on', MODEFR ← 'off', MODETE ← 'off', and MODEAGC ← 'on'.
   If the point is SUSPEND CONTROL, only MODEAGC ← 'suspend'.
   In all cases FLAGACE ← set and TIMEACE ← TIMEREAL.

10. When PSCHEDULS is entered, the 'POWER and ENERGY SCHEDULING' program must be called to rectify accounting procedures with a manual entry. Then PSCHEDULE ← PSCHEDULS, FLAGMOV ← set, TIMESCL ← TIMESCLS * 60, FLAGPES ← set and TIMESC ← TIMEREAL.
   If TIMESCLS ← is not entered before EXECUTE is pushed, TIMESCLS ← 10.
   When RESET is pushed, the 'POWER and ENERGY SCHEDULING' program must calculate the correct schedule and FLAGMOV ← clear.

GENERAL NOTES

This drawing is an example of the design which must be accomplished for each format. Each format should have the fields described where real time data supplied and used by the AGC algorithm is involved.

ALWAYS THINK SAFETY

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION
PICK-SLOAN MISSOURI BASIN PROGRAM
TRANSMISSION DIVISION - SOUTH DAKOTA

WATERTOWN AGC

DESIGNED	TECHNICAL APPROVAL
DRAWN	SUBMITTED
CHECKED	APPROVED — CHIEF, ELECTRICAL BRANCH
DENVER, COLORADO — JUNE 1, 1979	466-EP-52

Figure 34.—Generation control format module (Sheet 3 of 3).

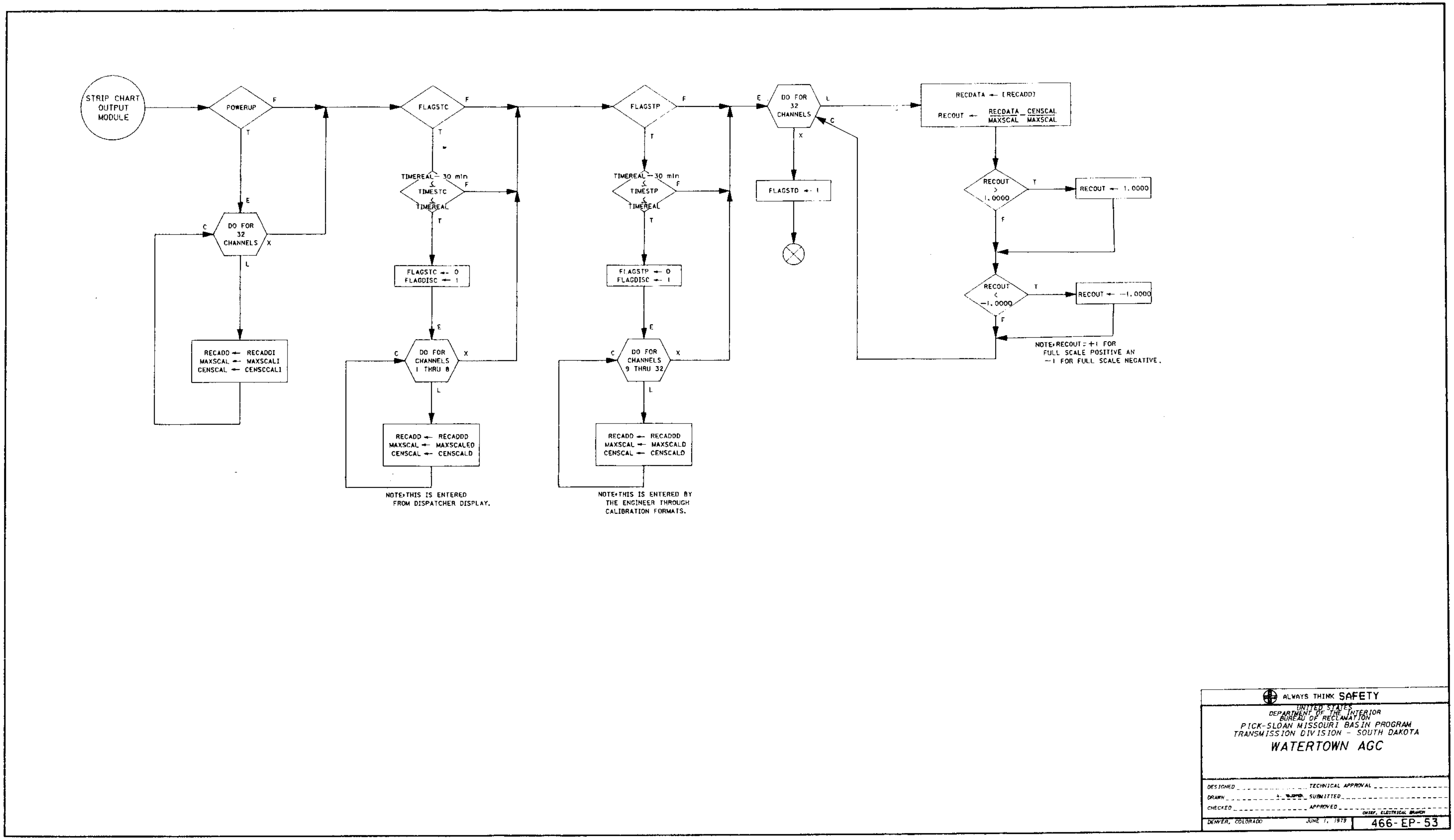


Figure 35.—Stripchart output module.

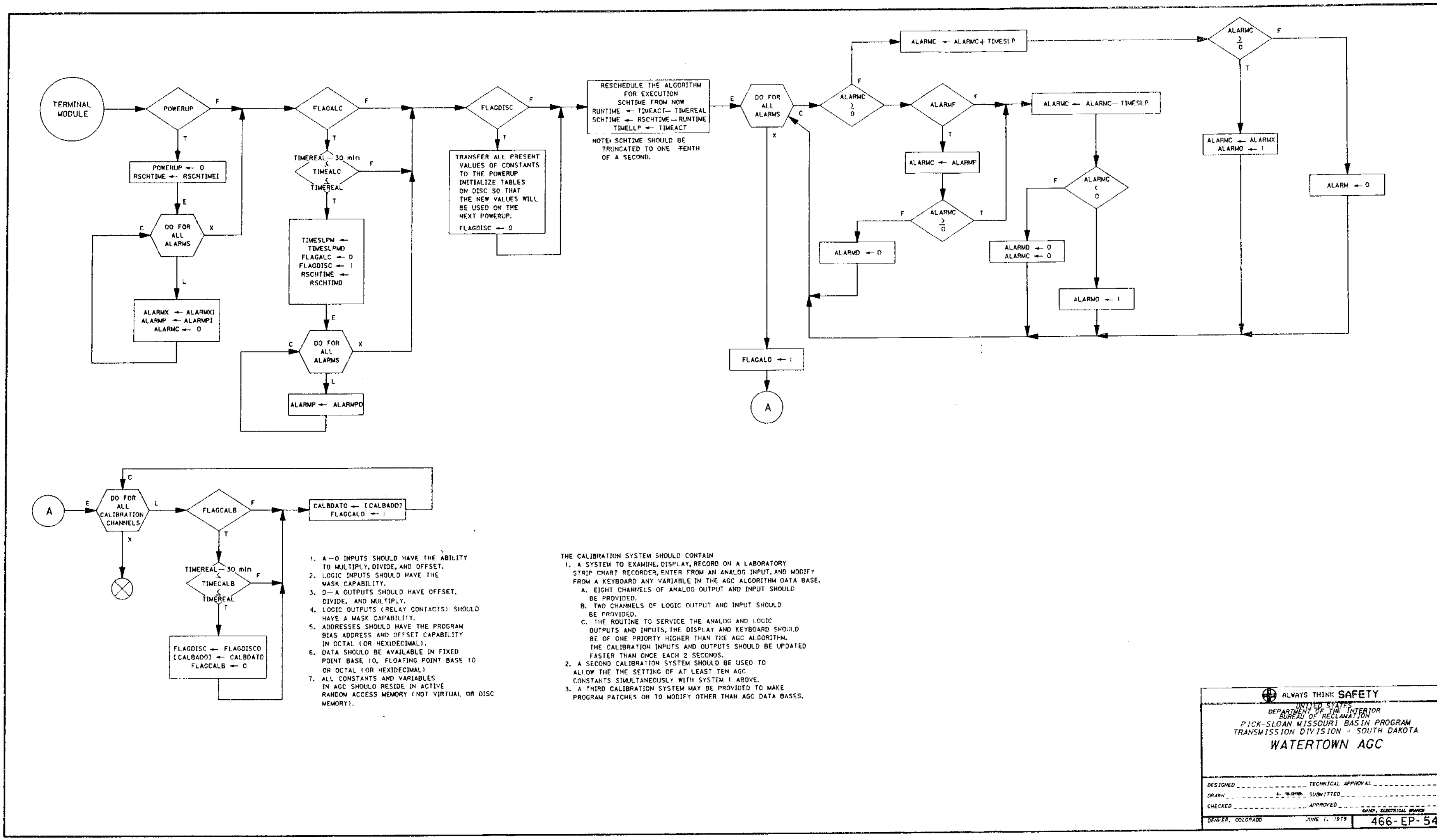


Figure 36.—Terminal module.

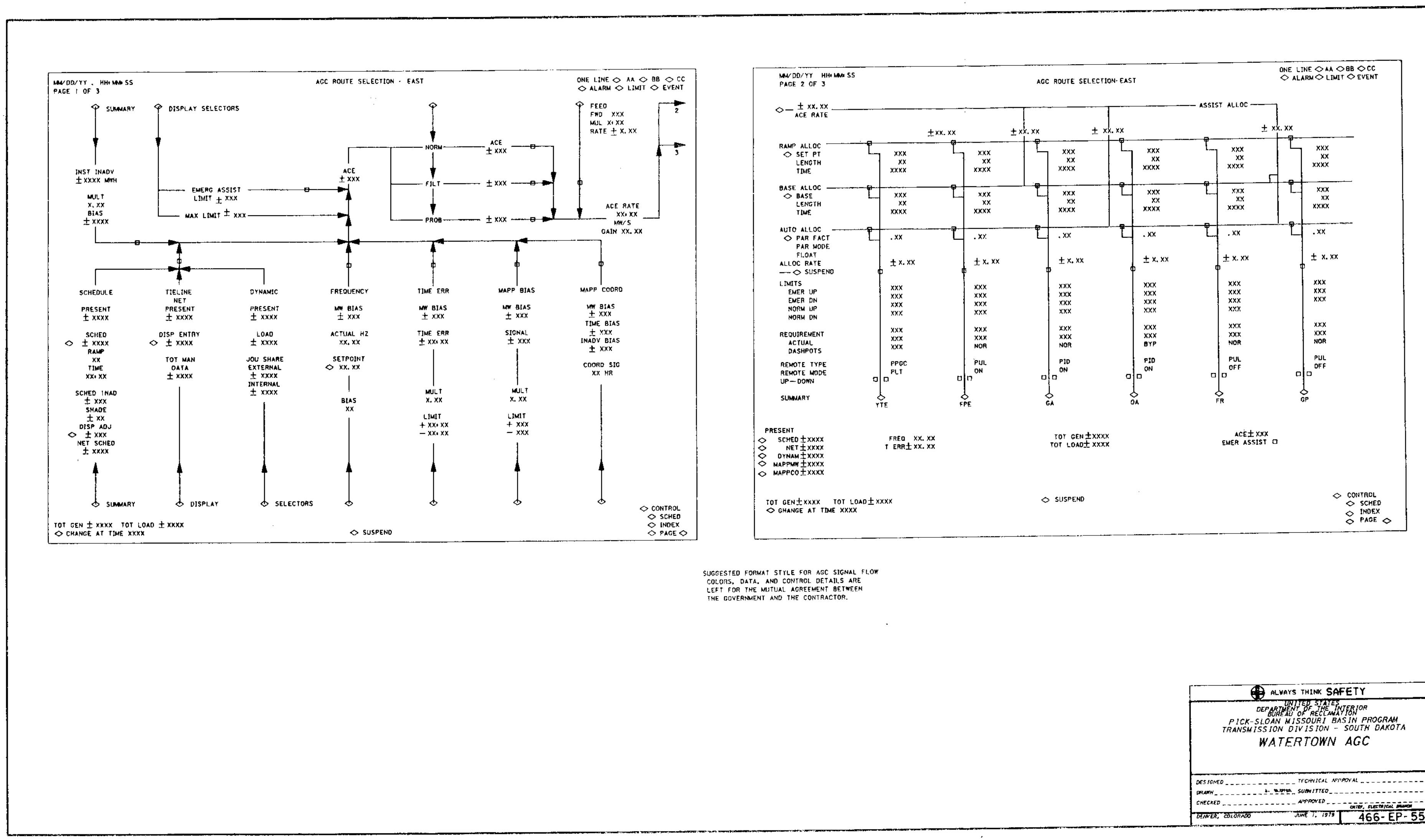
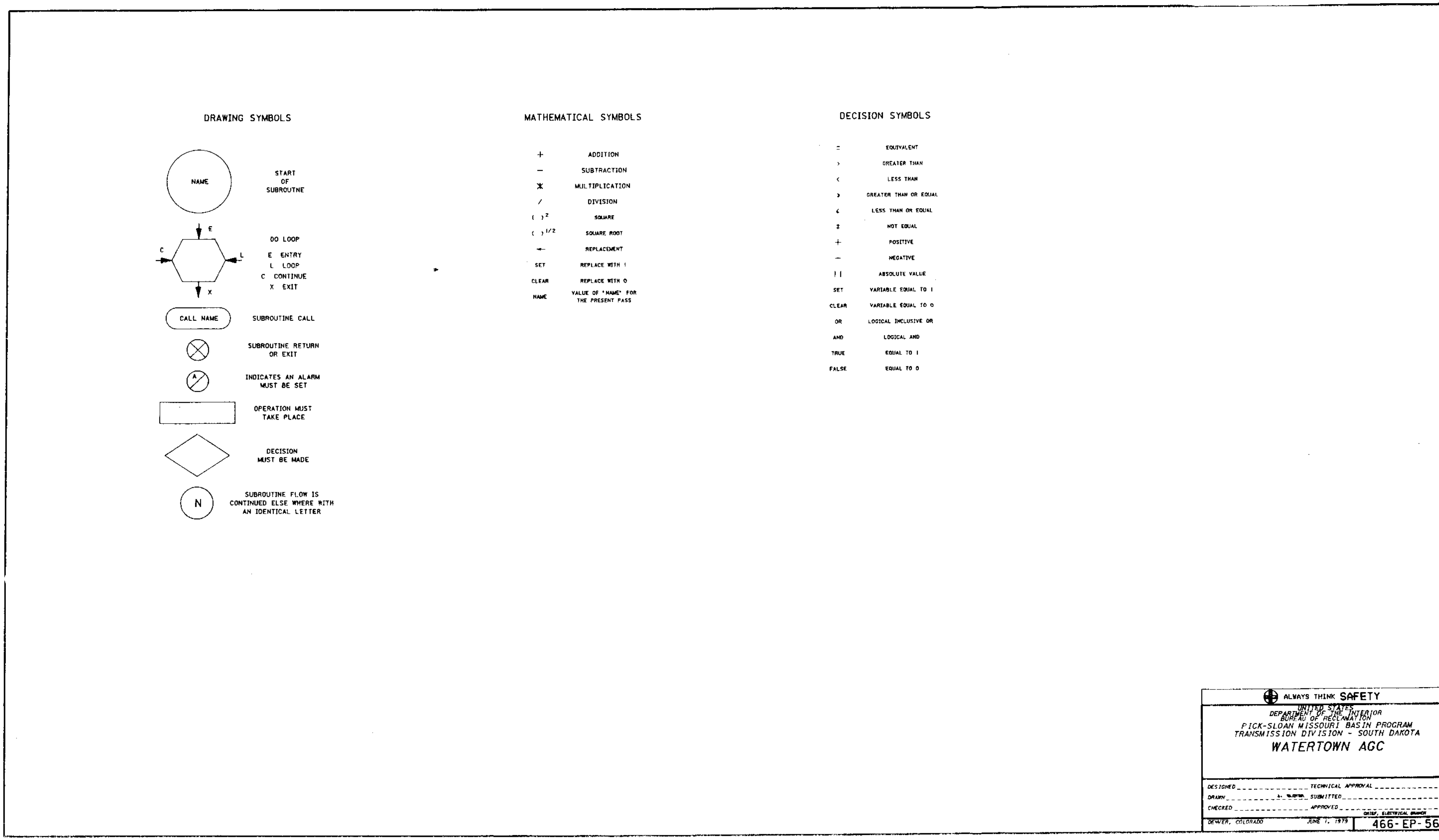


Figure 37.—Suggested format for AGC signal flow.



GPO 831-743

Figure 38.—Flow chart symbol definitions.