Transaction A	Input	Sequence	No.	= 30	Internal	Sequence		= 300
Transaction B	"	"	"	= 28	"	"		= 280
Transaction C	"	"	"	= 27	"	"		= 270

The spinning cost transaction will be assigned the sequence number 269.

The transactions will be processed incrementally with A first, any seq. no. = 29 transactions next, B, C and finally the spinning cost transaction.

b) If no transactions exist for the hour with the same transaction type and block no., an attempt is made to match a transaction type and (block no. +1). If a match is found, the sequence number is assigned to the minimum match sequence no. - 1, as in a).

c) If no transaction with the same transaction and (block no. + 1) is found, an attempt is made on transaction and (block no. - 1).

Note: If (block no. - 1) = 0, no attempt to match is made and the search continues with step d).

If a match is found, the sequence number of the spinning cost transaction is set to the maximum match sequence number + 1.

In the example shown in a), if the only short term transactions (other than spinning cost transaction) were block number = 1, the spinning cost transaction (block no = 2) would be assigned a sequence number = 301.

d) If no match is found under a), b) and c), a match on transaction type alone is attempted. If a match is found the sequence number assigned to the spinning cost transaction is the minimum match sequence number - 1. The example shown in a) would apply in this case if the block no. of transactions A, B and C had been 4.

e) If no match on transaction type is found, the sequence number is set to the minimum external delivery sequence number for the hour minus 1.

Note: In this case, the spinning cost transaction will be processed immediately before any Smith Mountain pumping schedule.

3.2 Allocation Processing

In each hour processed, the system losses are computed and deducted from the summation of generation levels of all units and amounts of all purchases. The resulting figure is the system load at the delivery point.

Next, the regulation costs for the system load at the delivery point, are computed. (See Section 4.1).

The processing of transactions or groups by descending sequence number is then performed as follows:

i) The total delivery for the transaction or group for the hour is deducted from the system load to give the new system load required at the delivery points.

ii) All direct allocations of source energy to the delivery transaction/group are processed and costs computed as described in Section 3.3.

iii) The total amount of energy directly allocated is compared to the total delivery for the group. If they are equal and losses are not to be computed, processing of transactions with the next highest sequence number is initiated.

iv) If the total amount of directly allocated energy does not equal the total delivery or losses are to be computed, the remaining energy requirement is incrementally allocated as described in Section 3.4 by economically dispatching the 'unit' generation to satisfy the new system load at the delivery points.

v) When any required incremental allocation of energy has been successfully completed, <u>corrections for losses</u> are made if necessary.

The economic dispatch routine dispatches the system generation to meet the load at the delivery points.

The economic dispatch routine determines the unit generation levels which include system losses. The difference in system losses for system load with and without a transaction, is therefore, the transaction losses. If losses are not required for a transaction or group, the transaction or group losses must be eliminated by re-dispatching the system. (See Section 4.3).

vi) When the final (i.e. post loss correction) generation levels have been established, the cost data for each generating unit is computed using the difference between the two generation levels corresponding to the system load with and without the incrementally allocated portion of the transaction/group.

These costs are added to costs by unit previously computed in ii). (See Section 6.3).

vii) If a group was processed the energy and costs are divided amongst the group in proportion to the scheduled delivery of each group member for the hour.

viii) If a jointly-owned unit was allocated, each member's share of energy and costs is divided amongst unit owners in proportion to their ownership percentage.

ix) If a system purchase is allocated to the delivery group, each transaction group member's share of energy and costs is divided amongst the pool members in proportion to the current MLR by the Reconstruction.

Processing of the next transaction or group begins with the computation of the new system load at the delivery points.

3.3 Direct Allocation Processing

For Reconstruction purposes, unit energy may be directly allocated to a delivery group/transaction as follows: -

a) An amount equal to the hourly normal low generation of the unit (default).

b) The total generation of the unit for the hour.

c) A specified (input) amount (0 < amount < hourly normal high).

d) A percentage of a), b) or c).

The maximum amount of energy to be directly allocated is determined from the input specifications during the edit of the input data. The edit process verifies that no unit has been allocated to more than one group or transaction for the hour if no percentage is input. If the percentage option is used, the edit checks to ensure that for any one hour the basis of allocation (normal low, total generation or specified amount), is the same for all allocations of a unit in a single hour and that the total percentage for the unit does not exceed 100%. As described in Section 3.2, when the system load at the delivery points has been determined for a group/transaction, the direct allocation of energy to that group/transaction is performed.

The term basic allocation amount is used to denote the amount of energy which forms the basis of direct allocation for the unit and hour. This amount is determined within the Reconstruction and is the lesser of the two amounts, the remaining unit energy and the specified maximum basis of allocation (i.e. normal low, total generation or specified amount prior to application of any percentage).

The costs applicable to the basic allocation of energy and method of computation depend on the number of MWH allocated as compared to the unit normal monthly high and low generation values.

If the basic allocation amount is less than the normal monthly low of the specified unit, the cost calculation is as follows: -

- The heat rate curve is used to compute the number of MBTU's required to maintain the monthly normal low generation level for 1 hour.
- Using the calculated MBTU's, the four cost items; 151-coal cost, 152-coal cost, incremental maintenance cost and tax are computed from estimated cost rates (in cents/MBTU) for the unit stored in the ECR Fuel Cost File. (See Section 6.3).
- The basic allocation amount is compared with the monthly low generation. If the two generation levels are not identical, the four cost items are prorated linearly to give allocation cost for the basic allocation amount.

If the basic allocation amount is greater than the normal monthly low generation of the specified unit but less than the actual hourly generation level, the cost calculation is performed as follows: -

i) Prior to processing the direct allocation input, the supplemental oil firing data for all units for the hour is processed. (See Section 6.1.3 for details).

This processing results in two generation cost curves for the unit and hour. (It is possible to have three valid generation cost curves for a unit and hour e.g. where a double-heat-rate-curve unit has supplemental oil firing).

oil normal high = unit normal high for hour
oil normal low = coal normal high
coal normal low = unit normal low for hour

The oil normal low is computed rounded <u>down</u> to the nearest MWH as described in Section 6.1.3.

ii) If the basic allocation amount is less than the coal normal high: -

- The heat rate curve is used to compute the number of MBTU's required to reach the allocation generation level.

- Using the calculated MBTU's, the four cost items 151-coal, 152-coal, incremental maintenance and tax are computed using the stored estimated coal cost rates (in cents/MBTU) for the unit. (See Section 6.3).

iii) If the basic allocation amount is greater than the oil normal low and less than the oil normal high and supplemental oil firing was used for the hour: -

- The heat rate curve is used to compute the number of MBTU's supplied by coal using the coal normal high as the generation-level.
- The heat rate curve is used together with the actual generation level to compute the total number of MBTU's required for generation.
- Using the coal-supplied MBTU's, the four cost items 151-coal, 152-coal, incremental maintenance (coal) and tax (coal) are computed using the estimated coal cost rates stored for the unit.
- The oil-supplied MBTU's are calculated by subtracting the coal-supplied MBTU's from the total required MBTU's.
- Using the oil supplied MBTU's and the stored unit estimated oil cost rates, (in cents/MBTU) the four cost items, 151-oil, 152-oil, incremental maintenance (oil) and tax (oil) are computed. (See Section 6.3).

When the costs of the basic allocation have been determined, the specified percentage is applied to both MWH and costs to give the current allocation MWH and costs. The term current allocation is used to denote the amount of energy directly allocated to a specific transaction/group from a specific unit. It is equal to unit's basic allocation multiplied by the percentage specified for the transaction/group.

Note: For any unit and hour, the basic energy allocation amount will be determined as part of the processing of the first transaction/group to which that unit is directly allocated. The basic allocation amount will be unchanged by subsequent transactions/groups processing for that hour. Direct allocation of the unit energy to subsequent transactions/groups will be performed using the same basic allocation amount and the percentage applicable to the transaction/group. If the total percentage allocation for the unit and hour is less than 100, the unallocated energy will be used to meet the AEP system internal load requirements.

If the specified transaction is a member of a group (i.e. there exists more than 1 transaction for a given sequence number for the hour), the current cost and energy allocation of the unit are divided amongst the group members according to the scheduled amount of energy delivered to each member for the hour.

If the unit is a jointly owned unit, the current cost and energy allocations to each group member are divided amongst the unit owners in proportion to their percentage ownership.

The applicability of tax charges is determined by the relative physical locations of the receiving company and delivering unit together with tax type (i.e. interstate or intrastate. (See Section 6.3.2).

The effect of the first direct allocation of a specified amount of unit generation on the subsequent incremental allocation of that unit's generation for the hour depends on the size of the basic allocation relative to the unit limits.

1) Basic allocation amount $\leqslant$ normal low
A basic allocation amount less than the normal low has no effect on normal incremental allocation of that unit's generation. To avoid over-allocation of energy during a low load condition (see Section 4.2), the oil point low and emergency minimum low are compared individually to the allocation amount and in each case set to the greater of the two values for incremental allocation purposes.

ii) Normal low $<$ basic allocated amount $\leq$ actual generation

In this case, the hourly normal low, oil point low and emergency minimum are all set to the basic allocation amount for incremental allocation. This procedure eliminates the possibility for allocating the same energy both directly and incrementally.

For the purpose of evaluation of <u>losses</u>, the directly allocated energy is subtracted from the available energy pertaining to the directly allocated source before any remaining required energy and any required losses for the specified transaction are incrementally allocated (see Section 4 for loss allocation description). The 'new' system load is unchanged by the direct allocation of energy. In order to subtract the directly allocated energy from the available energy, the unit characteristics are modified as follows: -

i) Normal Low = max (normal low, basic allocation) - current allocation amount

(minimum = 0)

ii) Emergency Minimum = max (emergency min, basic allocation) - current allocation amount

(minimum = 0)

iii) Oil Point Low = max (oil point low, basic allocation) - current allocation amount

(minimum = 0)

iv) Generation Level = remaining energy
= new normal low + generation - old normal low
(minimum = remaining energy available for incremental allocation).

The resulting unit characteristics are used in unloading all remaining transactions for the hour.

Note: Following each subsequent direct allocation for the same unit and hour, the characteristics are reduced further by the new current allocation.

The generation level used for incremental allocation cost purposes includes the directly allocated energy.

If the specified unit is in start-up during the period of direct allocation, a portion of the computed start-up cost for the unit will be assigned to the specified transaction. If the basic allocation amount is less than the hourly normal low, the start-up cost will be prorated (i.e. multiplied by (allocated MWH/normal low MWH)), otherwise the full amount will be assigned. Since the hour used for this cost assignment is the first hour of non-zero generation the amount of energy allocated will normally be less than the normal low and usually less than the specified allocation. (Allocation will be for available energy up to the specified allocation). Start-up costs will include: -

i) coal cost

ii) oil cost

iii) other cost

The specified percentage will then be applied to the start-up costs. Start-up costs will be distributed amongst transaction members of a group and unit owners in the same manner as energy costs.

3.4 <u>Incremental Allocation Processing</u>

After all direct allocation of energy for a delivery group/ transaction has been performed, the remaining energy required for the group/transaction is incrementally allocated. The steps required for the incremental allocation of energy are as follows:

i) The new system load is compared to the summation of the normal low generation levels for available units plus the 'normal lows' of available purchases plus the 'generation levels' of unavailable units and unavailable purchases.

If the new system load is less than this summation then a <u>low load condition</u> is in effect and the unit constraints are modified accordingly (see Section 4.2).

If the new system load is greater than the summation, i.e. the transaction or group can be unloaded, processing of the transaction proceeds.

ii) The system generation for the new level of system load is dispatched using the economic dispatch routine (see Section 7).

iii) The generation levels of the available sources are checked after the economic dispatch has been performed to determine if the source may be considered unavailable for future processing or a new generation cost curve must be considered. The process is performed as follows: -

a) The new generation level is checked against the previous level.

b) If the new level is higher than the previous level and equal to the high limit of the curve and a higher curve exists, the higher curve replaces the existing curve in the source data. The generation costs for the lower curve generation allocated to the transaction are credited to the transaction.

If the new level is lower than the previous level and equal to the low limit of the curve and a lower curve exists, the lower curve replaces the existing curve in the source data. The generation costs for the higher curve generation allocated to the transaction are debited to the transaction.

Note: Changes in curve data normally apply only to steam units.

c) For any source that did not meet the conditions in b), the new generation levels are reset to their previous values. If no source met the conditions in b), step d) is omitted. I.e., no re-dispatch is required unless a curve change is required by at least one source of energy.

Note: Resetting of levels on all unchanged units occurs when all units have been checked.

d) The economic dispatch is performed to redispatch the system generation.

e) If for any unit or purchase the lower limit of a generation cost curve has been reached and there is no lower curve (i.e., lower limit equals normal low), all available energy has been exhausted. In order to facilitate the economic dispatch, these units and purchases are made unavailable in the system configuration used for subsequent transaction or group processing for the hour.

Note: If a low load condition occurs, the units will be returned to available status. See Section 4.2.

iv) When the economic dispatch has been successfully completed, corrections for losses are made if necessary.

The economic dispatch dispatches the system generation to meet the system load at the delivery points. The economic dispatch determines the unit generation levels which include system losses. The difference in system losses for system load with and without a transaction, is therefore, the transaction losses. If losses are not required for a transaction or group, the transaction or group losses must be eliminated by re-dispatching the system. (see Section 4.3).

v) When the final (i.e. post loss correction) generation levels have been established, the cost data for each generating unit is computed using the difference between the two generation levels corresponding to the system load with and without the transaction/group.

These costs are added to costs by unit previously computed in iv). (See Section 6.3).

vi) If a group was processed, the generation and costs are divided amongst the group in proportion to the scheduled delivery of each group member for the hour.

vii) If a jointly-owned unit was allocated, each members' allocation is divided amongst unit owners in proportion to their ownership percentage.

viii) If a system purchase is allocated to the delivery group, each transaction group member's allocation is divided amongst the pool members in proportion to the current MLR by the Reconstruction. Processing of the next transaction or group begins with the computation of the new system load at the delivery points.

4.1 Cost of System Regulation

The costs of system regulation are defined as the costs incurred in MWH and $ by the AEP system because of the load-tracking allowance maintained in the operating level of the major units.

In order to allow for small load fluctuations to be met by the Load Frequency Control System during system operation, the major steam units have a peak operating limitation slightly below the normal high generation of the unit. This allows the generation level to rise in order to meet an increase in the system load.

To compensate for the loss of generation from units at their operating limits, other, more expenseive units operate at higher generation levels thus increasing the overall generation costs of the system.

The cost of system regulation is, therefore, the difference between actual system generation costs and the same system load economically dispatched with no allowance for load tracking.

In order to calculate these costs, the following steps are performed for each hour prior to the processing of any transactions or groups: -

i) The system losses are calculated and deducted from the summation of generation levels for all units and total amounts of all purchases to give the system load at the delivery points.

ii) The major steam units are made available for economic dispatch purposes (i.e., their generation levels may be modified hypothetically). All other units and all purchases are classified as unavailable for economic dispatch purposes (i.e., no changes will be made). This distinction is made since only those units controlled by the real time economic dispatch program are of concern in the calculation of regulation costs.

Note: Base loaded units and units using supplementary oil firing are not controlled by the real-time economic dispatch program and are, therefore, unavailable. All units controlled by the real-time economic dispatch program are considered major steam units.

Note: Units in start-up status are included as units available for the calculation of the cost of system regulation. The extent to which a particular unit participates is a function of the difference in actual and regulation high generation levels. The participation of start-up units in regulation may, therefore, be controlled by specifying regulation high limits where the hourly normal high for the unit would cause errors.

iii) The normal high generation levels of the major steam units are modified for regulation purposes as specified by SPPC to give the regulation high generation levels.

iv) An economic dispatch of the system generation to meet the load at delivery points is performed (see Section 7). The result is a new set of generating levels.

v) The cost of regulation is found by using the heat rate curve to compute the MBTU's required for the generation level of each major steam unit both before and after the economic dispatch. The difference in MBTU's for each unit is used together with the estimated unit rates from the ECR fuel cost file to compute: -

a) 151 fuel cost
b) 152 fuel cost
c) Incremental maintenance

See section 6.3.

The summation of these items over all available units gives the cost of system regulation.

vi) The difference in system losses before and after economic dispatch gives the MWH cost of regulation.

vii) If the post-economic dispatch generation level of a unit is equal to its regulation high generation level, the normal high generation level for the hour is set to the unit's actual (pre-economic dispatch) generation level.

If the generation level of a unit was constrained by regulation rather than economic considerations, the optimal generation level of that unit determined by the economic dispatch of the system load at the delivery points will equal the regulation high generation level of the unit. The regulation high generation of a unit is the high generation level of the unit in the absence of regulation considerations.

The normal high generation level is set to the actual generation level for units meeting this criteria, in order to include the effects of regulation in further unloading of the system (i.e., to prevent the unit generation levels from exceeding the actual limits required by regulation).

viii) The actual generation level of all available units are reset to their pre-economic dispatch levels.

Processing of delivery transactions and groups for the hour is then initiated.

4.2 Low Load Condition

Low load conditions normally occur only at low points in the system load. The low points in the system load occur normally on Sundays in early or late summer between midnight and 6 a.m.

A low load condition in the ECR System is said to occur when there exists one or more AEP System deliveries without which the generation levels on one or more of the AEP units would have been below the normal low of the unit.

In order to determine the existence of a low load condition in any hour, the normal minimum system load is computed before each transaction or group is processed. (It is computed prior to each processing cycle because of the unit availability constraints applicable to individual transactions or groups.)

In the ECR System, the normal minimum system load is the level to which the system may be unloaded incrementally and is computed as follows:

System normal minimum load = the sum of all available unit normal low generation levels plus the sum of 'normal lows' of available purchases plus the sum of generation levels of unavailable units and purchases.

I.e. System normal minimum load =

$$\sum_{i=1}^{NAU} G_{nl_i} + \sum_{j=1}^{NAP} P_{nl_j} + \sum_{k=1}^{NNU} G_{c_k} + \sum_{l=1}^{NNP} P_{c_l}$$

where NAU = no. of available units for transaction or group.

NAP = no. of available purchases for transaction or group.

NNU = no. of unavailable units for transaction or group.

NNP = no. of unavailable purchases for transaction or group.

G_{nl} = normal low generation level of units for incremental allocation for hour, (depends on amount of energy directly allocated from this unit).

P_{nl} = 'normal low' of purchase for incremental allocation for hours. (=0 or MWH of this purchase directly allocated to transactions or groups not yet incrementally processed for this hour).

G_c = generation level to which the unit has been unloaded by transaction or groups already incrementally processed for this hour, if any.

P_c = 'generation level' to which the purchase has been unloaded by transactions and groups already incrementally processed for this hour, if any.

When the system normal minimum load has been calculated it is compared with the system load at the delivery points which is to be met by the system generation.

If the <u>normal minimum is greater than</u> the <u>system load</u> economic dispatch of the units is not possible. The normal minimum system load is therefore replaced by the oil point minimum load by replacing the normal lows on available units with the oil point lows so that <u>oil point</u> <u>minimum load</u> =

$$\sum_{i=1}^{NAU^*} G_{op_i} + \sum_{j=1}^{NAP} P_{nl_j} + \sum_{k=1}^{NNU^*} G_{c_k} + \sum_{l=1}^{NNP} P_{c_l}$$

Where NAP, NNP, P_{nl}, G_c, and P_c are as before -

G_{op} = oil point low of unit for hour (depends on amount of energy directly allocated to this unit)

NAU*= no. of available units for transaction or group

NNU*= no. of unavailable units for transaction or group

NAU*, NNU* may differ from NAU, NNU respectively because units that were made unavailable because of incrementally reaching their normal lows will be re-instated as available.

If the oil point minimum load is less than the system load at the delivery points, the normal lows on all available units (including appropriate previously unavailable units) will be set to their respective oil point lows. The economic dispatch will then proceed normally.

If the oil point minimum load is greater than the system load at the delivery points, then the emergency minimum system load is computed by using the emergency minimum generation levels for available units.

Emergency Minimum System Load =

$$\sum_{i=1}^{NAU^*} G_{em_i} + \sum_{j=1}^{NAP} P_{nl_j} + \sum_{k=1}^{NNU^*} G_{c_k} + \sum_{l=1}^{NNP} P_{c_l}$$

Where NAU*, NAP, NNU*, P_{nl}, G_c, P_c are as before

G_{em} = emergency minimum generation level of unit for hour, (depends on amount of energy directly allocated from this unit).

If the emergency minimum system load is greater the system load cannot be dispatched economically. In this case, the available units are unloaded to their emergency minimum level. The average cost of energy of available units at emergency low generation level is then computed for each unit.

The system is then unloaded to meet the required system load by allocating the energy from the available units in descending order of computed average cost.

If the emergency minimum system load is less than the system load at the delivery points to be dispatched, the normal lows on all available (NAU*) units will be set to their respective emergency minimum generation levels. The dispatch of the system load using these 'normal' lows proceeds normally.

On completion of the dispatch, the generation levels of available units are checked against preceding levels. If any unit which was previously above its oil point low is now below the oil point low, the delivery transaction or group just unloaded will be credited with 'minimum credit' for the saving of oil not used. The 'minimum credit' is computed by multiplying the number of gallons of oil burned per hour by the estimated cost of oil in $/gallon.

The minimum credit will be distributed amongst group members and unit owners in the same manner as all other costs.

4.3 Allocation of Losses

It is normal for the generation cost of system (transmission) losses to be included in the out-of-pocket costs of an AEP supplied delivery transaction or group.

It is also normal for the generation cost of system (transmission) losses for an AEP transmitted delivery transaction or group to be part of the AEP system internal load costs. The with/without losses difference in out-of-pocket cost is usually compensated by the rate structure.

In the use of the economic dispatch routine (see Section 7), the load is the system load at the delivery points (i.e. excluding system losses). System losses on that load are always included in the computations and reflected in the generation levels determined by the routine. No differentiation is made by the routine between the generation for energy deliveries and that for losses.

If losses are not requested, for out-of-pocket costs of energy delivery for a particular transaction or group, a correction for losses must be made after the system generation has been dispatched.

The system losses at a particular system load at the delivery points are determined by the economic dispatch routine. The system losses associated with a particular transaction or group are, therefore, to be computed as the difference in system losses between those for the system load with and without the transaction or group.

I.e.:

Let SL_1 be the system load at the delivery points prior to processing the transaction or group.

SL_2 be the system load at the delivery points after processing the transaction or group.

TE be the scheduled delivery to the transaction or group.

L_1 be the system losses at system load SL_1.

L_2 be the system losses at system load SL_2.

TL be the system losses associated with the transaction or group.

<u>Total</u> system load prior to processing the transaction or group = $SL_1 + L_1$.

$SL_2 = SL_1 - TE$ $\qquad$ $TL = L_1 - L_2$

In order to include the transaction or group losses with the AEP system load (for transmissions), these losses must be allocated back into the system.

The losses are allocated back into the system by adding the transaction or group losses (TL) to the system load ($SL_2 + L_2$) to give the system load ($SL_2 + L_1$) for the transaction energy delivery only. This load is then dispatched to give the generation levels for the transaction energy delivery.

It should be noted that since the transaction losses are normally small (< 10 MWH), the dispatch of the system will normally return a system load at the delivery points equal to that requested. (I.e. no change in losses will occur because of the small change in system load at the delivery points).

If there is a change in losses incurred because of the change in the system load at the delivery points, the system load is readjusted for the new change in losses and the procedure is repeated. See Section 7. This process then gives the required 'after-processing' total system load of $SL_2 + L_1$.

4.4 Spinning Cost Computation

The term 'spinning cost transaction' is used in this section to denote an ECR-generated transaction used to evaluate spinning costs associated with an energy delivery transaction/ group. The notation 'spinning cost' is used to distinguish this generated transaction from its associated energy delivery transaction/group.

Spinning cost computations are performed at the discretion of SPPC to evaluate and recover the cost of the inclusion of specific units in the system configuration. The decision to charge the spinning cost of a unit to a specific delivery transaction or group is based on: -

a) The unit generation was not required by the AEP system to meet its internal load.
b) The receiving foreign company has agreed to pay spinning costs for the unit.

The purpose of the spinning cost computation is to charge the receiving company for the <u>effective</u> cost of the inclusion in the system configuration of the higher cost energy generation below the normal low generation level of the specified unit. This energy may not normally be incrementally allocated to delivery transactions and is, therefore, used to meet the AEP system internal load requirement unless it is directly allocated to a delivery transaction.

The spinning cost computations will be performed when: -

a) an implied request for spinning cost is made or
b) a specific request for spinning cost is made.

a) An <u>implied request</u> for spinning costs to be calculated is made when a unit is directly allocated to a delivery transaction for a time period in which the scheduled delivery for an hour is 0 MWH or less than the amount of direct allocation.

The spinning costs are computed as follows: -

i) The direct allocation is processed and costs are computed in the normal manner, (see Section 3.3) and the transaction or group is debited with the total applicable cost for the hour.

ii) The delivery transaction may have no sequence number specified for the hour (e.g., if the scheduled delivery amount is 0, there may be no entry via the MHO system for sequence number). In this case a sequence number is assigned. (See Section 3.1).

iii) In the incremental allocation processing of the transaction or group, the spinning cost transaction is processed normally (see Section 2.2) except for the following: -

a) The direct allocation processing has allocated more energy to the transaction/group than was required. This allocation was achieved by changing the specified unit characteristics (see section 3.3). The effect of the changed characteristics together with the system load at the delivery points will be that the generation levels returned by the economic dispatch routine will indicate increases in the individual generation levels of the available units. These increases will compensate for the direct allocation.

b) Since spinning cost cannot include losses, the correction for losses is always made.

c) The resulting cost data is a <u>credit</u> to the delivery transaction or group. (A positive change in the system load at the delivery points, will result in a net increase in the generation levels of the sources. The net cost of the increase in system load will, therefore, be a credit amount). See Section 2.2, iv) b.

v) The results of the economic dispatch (i.e., generation levels) are used as input for processing the next transaction or group.

b) A <u>specific request</u> for spinning costs to be calculated is made at the discretion of SPPC.

In this case, the units and possibly the energy associated with the spinning costs must be specified by SPPC.

- MWH values are associated with the specified delivery transaction and are interpreted to be the amount of energy for which spinning costs are to be computed. The specific transaction may be a member of a group. If no value is specified, the scheduled delivery amount is used.
- Unit codes are associated with the group of which the specified transaction is a member and are interpreted to be the units for which the group spinning costs are to be computed.

I.e., the generation of these units would not have been required by the AEP system except for the required delivery.

At least one entry must be made for each group requiring spinning cost calculations. A unit which has been <u>directly allocated</u> in any manner to any transaction <u>may not</u> be specified for spinning cost calculation.

The spinning costs are computed as follows: -

i) The allocation of energy to meet the scheduled delivery requirements of the transaction or group proceeds normally (see Section 2.2).

ii) The amount of energy for which spinning cost is to be computed is calculated by summation of the input MWH or scheduled delivery MWH for each member of the group.

iii) The system load at the delivery points for the spinning cost calculation is the computed system load resulting from step 1) <u>plus</u> scheduled group delivery <u>minus</u> spinning cost energy.

iv) The specified units are removed temporarily from the system configuration.

v) The spinning cost system load is dispatched normally.

vi) A correction for system losses is made (see Section 4).

vii) The spinning costs are computed from the generation level changes made by the economic dispatch and <u>debited</u> to the group or transaction.

<u>Note</u>: In the case of an implied request for spinning cost calculation, the debit is made during the direct allocation processing. A credit is made for the

directly -allocated energy not delivered, during incremental allocation processing. The cost of the directly allocated energy will always exceed the cost of the incrementally allocated energy. The net result will, therefore, be a debit to the transaction for spinning costs.

In the case of a specific request, the same result is achieved in a single step by the exclusion of the specified units from the system configuration as described in iii) and iv).

The processing of a transaction or group for energy and spinning cost may be described as follows: -

Let SL_1 be system load of delivery points prior to processing of group or transaction.

SL_2 be system load at delivery points after processing of scheduled delivery to the group/transaction.

SL_3 be system load at delivery points for spinning cost calculation.

TE be scheduled delivery to group or transaction.

SE be spinning energy for the group or transaction.

L_1 be system losses at system load SL_2.

TL be transaction or group losses (may be 0 if required).

UA_1, UA_2, UA_3 be generation levels on non-spinning available units at system loads SL_1, SL_2, SL_3, resp.

US_1, US_2, be generation levels of spinning units of loads SL_1, SL_2 resp.

PA_1, PA_2, PA_3 be 'generation' levels of available purchases at system loads SL_1, SL_2, SL_3.

NAU be no. of non-spinning available units for group energy processing.

NAP be no. of non-spinning available purchases for group energy processing.

NUS be no. of units specified for spinning.

G be summation of operations levels of all unavailable sources (units and purchases) for group energy processing.

Prior to processing scheduled delivery of energy

$$SL_1 + L_1 = \sum_{i=1}^{NAU} UA_{1_i} + \sum_{j=1}^{NUS} US_{1_j} + \sum_{k=1}^{NAP} PA_{1_k} + G$$

System load after processing scheduled group delivery = SL_2

where $$SL_2 + L_2 = \sum_{i=1}^{NAU} UA_{2_i} + \sum_{j=1}^{NUS} US_{2_j} + \sum_{k=1}^{NAP} PA_{2_k} + G$$

and $SL_2 = SL_1 - TE, \qquad L_1 = L_2 + TL$

System load after processing spinning cost = SL_3

where $$SL_3 + L_3 = \sum_{i=1}^{NAU} UA_{3_i} + \sum_{k=1}^{NAP} PA_{3_k} + G$$

and $SL_3 = SL_2 - SE + TE = SL_1 - SE$

$$\text{Energy costs} = \sum_{i=1}^{NAU} f(UA_{1_i} - UA_{2_i}) + \sum_{j=1}^{NUS} f(US_{1_j} - US_{2_j}) + \sum_{k=1}^{NAP} g(PA_{1_k} - PA_{2_k})$$

$$\text{Spinning costs} = \sum_{i=1}^{NAU} f(UA_{1_i} - UA_{3_i}) + \sum_{j=1}^{NUS} f(US_{2_j}) + \sum_{k=1}^{NAP} g(PA_{2_k} - PA_{3_k})$$

5. Special Plant Handling

a) Donald C. Cook

The Donald C. Cook plant is currently base loaded and is, therefore, not available at any time for incremental allocation. It is included in the system configuration throughout the incremental allocation as not available. It is included for the purpose of losses computation only.

If it becomes necessary, these units can be included in the ECR system configuration and their energy allocated normally.

b) Smith Mountain Pumped Hydro

For incremental allocation purposes, Smith Mountain units are considered as a single fixed-rate source. Estimated cost rates in mills/kwh for the units and month is stored in the ECR Fuel Cost File as 151-coal and 152-coal cost rates.

The 'generation' cost curves for the unit are created in a manner identical to that for purchases (see Section 6.2) for use in incremental allocation.

The energy supplied by the AEP system for pumping is treated as delivery to a foreign company. This is done internally to the ECR system, by creating a delivery 'transaction' for each hour of pumping. (The pumping schedule is input to ECR). This transaction is given the lowest possible sequence number in order that the cheapest energy available after internal system load is satisfied, is allocated to pumping.

This transaction is incrementally allocated normally as part of the hourly reconstruction process.

The actual generating rate for the unit and month is calculated by dividing the summation of actual pumping costs for the calendar month by the total generation for the calendar month. This rate is calculated when actual fuel cost rates for the coal and oil fired units are available. This procedure is performed as part of monthly adjustment of delivery transaction costs for the the difference between estimated and actual fuel costs. It is not performed as part of the Reconstruction.

c) <u>Hydro Unit</u>

The hydro units are included in the system configuration as unavailable for incremental allocation purposes.

This is in order that their generation may be included for losses computation purposes. No cost is associated with the hydro units in the ECR System.

6. Generation Cost Calculation

6.1 Major Steam Units

6.1.1 Single Curve Units

For each major steam unit, there exists at least one set of heat rate curves of the form -

$$MBTU = A + B * MW + C/2 * MW^2$$

Each heat rate curve in a set is associated with a river water temperature. Currently each set consists of four curves; one for each temperature 40°, 65°, 75°, and 80°. The curve in each set to be used during reconstruction is determined by SPPC and stored in the ECR Fuel Cost File (usually on a monthly basis). The limits of applicability of the curves in a set are the monthly normal high and low generation levels of the unit.

Energy generated by each unit may be incrementally allocated between the hourly curve high and low limits.

Note: The lower limit may be modified for incremental allocation purposes by the direct allocation of the unit generation (see Section 1.1.1).

The cost of incrementally allocated energy is computed by applying the cost rates stored in the ECR Fuel Cost File (in cents/MBTU) to the difference in the number of MBTU's is required for unit generation at the levels before and after the allocation. (See Section 6.3).

All energy generation below the monthly normal low is assumed to have a linear cost function. Any allocation of this energy is prorated linearly to the total cost of generation at the monthly normal low.

Note: The monthly normal low is used because the hourly normal low may radically depart from the monthly level (in start-up, etc.). No attempt is made by the ECR System to determine if the difference in the two levels is small enough to ensure the curve is applicable for the hourly normal low. (The use of the monthly normal low for the computation of the cost of directly allocated energy does not affect the use of the hourly normal low as a limit of generation levels).

Energy generation below the hourly normal low may only be allocated directly.

$$\text{The cost of allocation} = \frac{\text{no. of MWH allocated}}{\text{monthly normal low}} \times \text{(cost of generation at montly normal low)}.$$

6.1.2 Multiple Curve Units

Multiple curve units have more than 1 set of generation cost curves (usually 2 sets). These units may be units with an alternative feed water pump energy source.

Each set will have an identical number of curves (currently 4) with the same river water temperature associated with 1 curve in each set. A curve from each set is applicable for incremental allocation purposes in any one hour for these units. It should be noted that a 2-boiler unit is not considered a multiple curve unit by the ECR System. Since the elapsed time involved in changing a unit from single boiler operation to double boiler operation is several hours, only one of the two applicable heat rate curves is pertinent in a single hour. The curve to be used for incremental allocation purposes is determined by the actual generation level of the hour.

The allocation of generation below normal low is identical to that for single curve set units (see Section 6.1).

Incremental allocation is performed using all valid curves. A single curve is passed to the economic dispatch routine for any dispatch of system generation.

The curve to be used is determined by the generation level of the unit as passed to the economic dispatch routine.

E. g., for a unit x the limits may be as follows: -

High Generation Level = 600 MW

High Curve Lower MWH Unit = 400 MW

Low Generation Level = 300 MW

Low Curve Coefficient A_1, B_1, C_1 &

High Curve Coefficient A_2, B_2, C_2

For system generation dispatch when the level of the unit determined by the last dispatch (or actual for the first dispatch) is 500 MW, the economic dispatch routine would received the following unit data:

High Generation Level = 600 MW

Low Generation Level = 400 MW

Curve Coefficents A_2, B_2, & C_2

If the level determined by the previous dispatch routine was 375 MW the economic dispatch routine would receive the following unit data:

High Generation Level = 400 MW

Low Generation Level = 300

Curve Coefficient A_1, B_1, & C_1

The decision to change unit data is made within the incremental allocation processing as follows: -

i) After dispatch of system generation for a specific system load at the delivery points, the new generation level of each unit is checked against its prior level.

ii) If the new level is higher than the old level <u>and</u> equal to the high limit of the curve <u>and</u> a higher curve exists, the higher curve is used for a new dispatch of the same system load.

iii) If the new level is lower than the old level <u>and</u> equal to the lower limit of the curve <u>and</u> a lower curve exists, the lower curve is used for a new dispatch of the same system load. See Section 2.2.2 iv) for calculation details.

6.1.3 <u>Supplemental Oil Firing</u>

When oil is used for supplemental firing of a unit which is normally totally coal fired, it is assumed that oil is used to raise the actual generation level because of temporary physical constraints on the level of coal-fired generation attainable.

It is, therefore, assumed that the oil fired generation is on the highest portion of the heat rate curve.

This leads to an additional generation cost curve applicable for the unit. The basic MBTU = f (MW) equation is unchanged but the cents/MBTU rate changes giving a different generation cost equation $ = g (MW). Since the economic dispatch routine uses generation cost curves, a new curve for oil generation must be considered in the incremental allocation of energy.

The limits of the oil generation cost curve are established as follows: -

i) The number of MBTU's required to maintain the actual generation level of the unit is computed using the applicable curve.

ii) The number of oil-supplied MBTU's/hour is computed from the heat content of oil stored in the ECR Fuel Cost File and the number of gallons of oil burned for the unit and hour input by SPPC.

iii) The number of coal-fired MBTU's/hour is computed by deducting the oil-fired MBTU's/hour from the total required MBTU's/hour.

iv) A solution for the number of coal-fired MWH is found using the generation cost curve and the coal-fired MBTU's/hour.

Note: Since MBTU is a quadratic function of MW, two solutions are possible. The higher of the two is always taken as the correct solution.

The resulting solution is rounded down to the nearest MWH.

v) The coal-fuel curve high limit is set to the number of coal-fired MWH.

The oil-fired low limit = coal-fired high limit
oil-fired high limit = hourly high generation level

E.g. expanding the example in Section 6.1.2, if it were established that the top 50 MW had been oil fired the following unit data would be used (1 set at a time) for incremental allocation.

	High	Low	Curve Coefficients
Oil-fired High Curve	600	550	A_2', B_2', C_2',
Coal-fired High Curve	550	400	A_2, B_2, C_2
Coal-fired Low Curve	400	300	A_1, B_1, C_1

Where A_2', B_2', C_2', were the high curve coefficients for oil cost

A_2, B_2, C_2 were the high curve coefficients for coal cost

A_1, B_1, C_1 were the low curve coefficients for coal cost

The criteria used to determine which curve is to be used or that a change of curve is required are identical to those defined in Section 6.1.2.

6.2 <u>Fixed Rate Sources</u>

The term 'fixed rate sources' as used in this section includes purchases (i.e., Purchased Power or Interchange-In transactions), pumped-hydro units and other sources.

In order to include fixed rate sources as available sources for incremental allocation, each source is modelled as if it were a unit.

The <u>normal low</u> for the source is initially set to 0. This may be modified by direct allocation of the source as described in Section 1.2.1. The <u>normal high</u> is set to the scheduled receipt (for purchases) or the generation level (for Smith Mountain). The available energy for incremental allocation is equal to normal high - normal low.

In order to model a fixed rate source as a unit, a generation cost curve (see Section 6.3.1) of the following form is required:

$$\$ = A' + B'*MWH + C'/2 *MWH^2$$

However, as described in Section 7, the economic dispatch routine uses the derivative of the generation cost curve. This equation is in the form of a straight line as follows: -

$$\frac{d\$}{d(MWH)} = B' + C'*MWH$$

Therefore, for economic dispatch purposes, only the B and C coefficients of the generation cost curve for a fixed rate source need be set by the ECR System.

The value of the coefficient C is set to the minimum possible value that will allow for incremental allocation (i.e. convergence of the incremental rate, λ).

The value of the coefficient B is set as follows: -

B = fixed rate (in $/MWH) - (available energy*C/2).

6.3 Energy Cost Calculations

6.3.1 Unit Fuel and Maintenance Cost

The economic dispatch routine uses the B' and C' coefficients of the generation cost curve of a unit to determine the generation level of a unit.

The generation cost curve is derived from the heat rate curve as follows: -

Heat Rate Curve - $MBTU = A + B*MWH + (C/2)*MWH^2$

Generation Cost Curve - $\$ = A' + B'*MWH + (C'/2)*MWH^2$

Where A' = A*Cost in cents/MBTU

B' = B*Cost in cents/MBTU

C' = C*Cost in cents/MBTU

and

A is in (MBTU)

B is in (MBTU/MWH)

C is in $(MBTU/MWH^2)$

Cost = {151 fuel rate + 152 fuel rate + incremental maintenance + tax} for a unit in estimated cents/MBTU.

In order to compute the cost of allocated energy, the heat rate curve is used. The generation cost curve could also be used but the MBTU's and individual cost items are required by the ECR system.

The costs are computed as follows: -

The total MBTU's ($MBTU_1$) required by the unit to maintain its pre-dispatch generation level for 1 hour are computed from the heat rate curve.

The total MBTU's ($MBTU_2$) required by the unit to maintain the generation level of the unit determined by the economic dispatch routine are computed in a like manner.

The MBTU's supplied to the unit used by the transaction/group being processed is $MBTU_1$ minus $MBTU_2$.

Costs of energy allocated to the transaction/group are as follows: -

151 Fuel Cost	=	($MBTU_1$ - $MBTU_2$) *151 est. fuel rate
152 Fuel Cost	=	($MBTU_1$ - $MBTU_2$) *152 est. fuel rate
Incr. Maint. Cost	=	($MBTU_1$ - $MBTU_2$) *Est. Incr. Maint. rate
Tax	=	($MBTU_1$ - $MBTU_2$) *Est. tax rate

The estimated fuel and incremental maintenance are stored monthly in the ECR files by other components of the system. The tax rate for a unit is computed for each reconstruction job by multiplying the tax rate in % stored in files by the sum of the estimated fuel rates and incremental maintenance rates.

6.3.2 <u>Unit Tax Costs</u>

As described in 6.3.1, the tax costs associated with an allocation of unit energy to a transaction or group are always computed.

After the energy cost computation has been completed, the costs are divided amongst the members of the group in proportion to their delivery MWH schedule if required. When this process is completed, the costs of allocated energy between a unit and an individual transaction are known.

The tax code applicable to the unit and the locations of the unit and the transacting foreign company are checked for applicability of tax. E.g. if the tax code denotes inter-state and the state locations are identical, the tax cost is set at 0.

If the combination of tax code and locations indicates tax is not to be charged, the tax cost is set to zero for file storage and reporting purposes.

6.3.3 Fixed Rate Source Cost

As described in Section 6.3.2, in order to allocate the energy available from fixed rate sources, these sources are modelled as units. This modelling does not affect the method of computing the cost of allocation of a fixed rate source.

The costs are computed by multiplying the fixed rates by the MWH of allocation.

For any purchase or interchange source 3 different elements of cost rate may exist.

They are	A) Fuel cost rate	($/MWH)
	B) Includable non-fuel	($/MWH)
	C) Other	($/MWH)

From these rates, four allocation costs are computed -

1. Fuel cost
2. Includable non-fuel cost
3. Other cost
4. Total cost

Note: Includable non-fuel cost and other cost are normally mutually exclusive. For purchases or interchange sources, the non-fuel portion of the cost is considered as includable for receipts of energy made on an economy basis. For non-economy receipts, the non-fuel portion of the cost is not includable and is counted as other cost.

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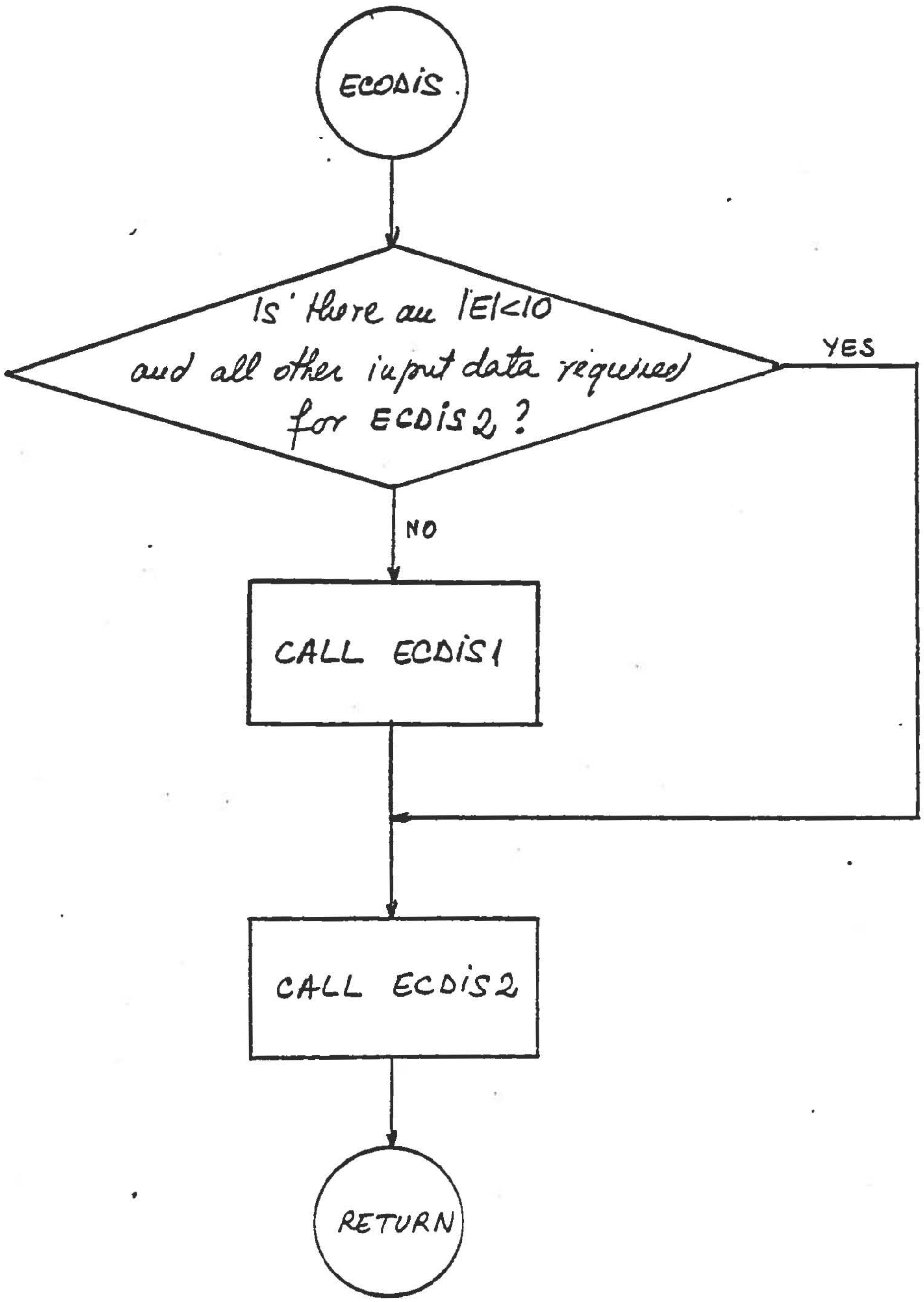
Section 7

ECONOMIC DISPATCH SUBROUTINE



Subroutine ECDIS 1

1. Input

- sources to be allocated incrementally

  $i = 1,..,N$

- sources not available for incremental allocation and their generation level (MW)

  $i = N+1,..,M$

  $G_{N+1},..,G_M$

- sources generation limits (MW)

  $\left.\begin{array}{l} L_i \text{ (low)} \\ H_i \text{ (high)} \end{array}\right\} \quad i = 1,..,N$

- cost curve slope and intercept for sources to be allocated

  $$y = \frac{S_i}{2} x^2 + I_i x + C$$

  where y represents cost and x generation (hundred MW)

  $\left.\begin{array}{l} S_i \text{ (slope)} \\ I_i \text{ (intercept)} \end{array}\right\} \quad i = 1,..,N$

- axis number for all sources

  $f(i) \quad i = 1,..,M$

- loss formula coefficients: $B_{f(i)f(j)}$, $B_{f(i)o}$, B_{oo} indexed by axis number and expressed in per unit on a 100 MWH base

- load to be dispatched incrementally L(MW), measured at the delivering points

2. Output

- system λ (incremental cost)
- sources generation level P_i, $i = 1,..,N$ (MW)
- system losses SL (MW)
- system load error E (MW)

3. Subroutine Constants

ε_1 = tolerance for source generation level

$$\varepsilon_1 = .001 \text{ (hundred MW)}$$

ε_2 = tolerance for system load level

$$\varepsilon_2 = 10 \text{ (MW)}$$

NS = maximum number of steps allowed for load convergence

$$NS = 10$$

$\lambda_o = 0$

λ_1 = initial incremental cost *)

G_i, $i = 1,...,N$ = initial generation level for sources to be allocated incrementally *) (MW)

4. Computational Definitions

Let P_n, $n = 1,..,M$ be the generation level for source (n) (hundred MW).

The tentative coordination equation for source i, $i = 1,..,N$, is:

$$S_i P_i + I_i + \lambda\left(2\sum_{n=1}^{M} B_{f(i)f(n)} P_n + B_{f(i)o}\right) = \lambda$$

Notice that for $n = N+1,.., M$, $P_n = G_n$ (constant)

*) When we are able to identify reasonable initial values for λ_1 and the corresponding G_i, $i = 1,..,N$, we can transmit these constants as input parameters. Otherwise, we should have default values like:

$\lambda_1 = 2$

$G_i = L_i \quad i = 1,..,N$

The corresponding system losses are:

$$SL = \sum_{m=1}^{M} \sum_{n=1}^{M} B_{f(m)f(n)} P_m P_n + \sum_{n=1}^{M} B_{f(n)o} P_n + B_{oo}$$

The constraint equations are:

$$100 \left(\sum_{i=1}^{M} P_i - SL \right) = L \text{ (system load constraint)}$$

and $\frac{L_i}{100} \leq P_i \leq \frac{H_i}{100}$ $i=1,\ldots N$

The solution is found by determining feasible generation levels P_i, $i=1,..,N$, for successive estimated values of λ, until the system load constraint is satisfied within a tolerance ε_2.

For a given λ, the feasible generation levels P_i, $i=,..,N$, are calculated to satisfy best the coordination equations. This is achieved by using the Gauss-Seidel iterative method. The method uses an initial set of P_i, $i=1,..,N$, and is improving the P_i's one after another by solving successively the coordination equations and substituting for any solution of P_i outside its feasible range $\left(\frac{L_i}{100} \; \frac{H_i}{100}\right)$, the range limit closest to it.

Thus: $$P_i = \frac{1 - I_i/\lambda - \left(2 \sum_{n \neq i} B_{f(i)f(n)} P_n + B_{f(i)o}\right)}{S_i/\lambda + 2B_{f(i)f(i)}} \quad i=1,..,N$$

The procedure starts with Step 1.
The initial values are:

λ_1 and

$P_{i,o} = G_i/100$ $i=1,..,M$

One Step (ℓ) consists of solving the coordination equations for a given λ_ℓ and checking the constraint equation, which might result in either stopping the procedure or calculating $\lambda_{\ell+1}$ and going to Step (ℓ+1).

Step ℓ

$$P_i^{(o)} = P_{i,\ \ell-1} \quad i=1,..,N$$

Part I (Gauss-Seidel method):

Part I starts with iteration 1. Iteration (k) is calculating $P_i^{(k)}$, $i=1,..,N$ as function of $P_n^{(k-1)}$ for $n>i$ and $P_n^{(k)}$ for $n<i$, as follows:

$$P_i^{(k)} = \frac{1 - I_i/\lambda_\ell - (2\sum_{n\neq i} B_{f(i)f(n)} P_n^{*} + B_{f(i)o})}{S_i/\lambda_\ell + 2B_{f(i)f(i)}} \qquad i=1,..,N$$

where $P_n^{*} = \begin{cases} P_n^{(k)} & n=1,..,i-1 \\ P_n^{(k-1)} & n=i+1,..,M \end{cases}$

If $P_i^{(k)} < L_i/100$ make $P_i^{(k)} = L_i/100 \quad i = 1,..,N$

If $P_i^{(k)} > H_i/100$ make $P_i^{(k)} = H_i/100 \quad i = 1,..,N$

If $|P_i^{(k)} - P_i^{(k-1)}| \leq \varepsilon_1$ for all $i = 1,..,N$,

make $P_{i,\ell} = P_i^{(k)}$ and go to Part II.

If there is a $i = 1,..,N$ such that $|P_i^{(k)} - P_i^{(k-1)}| > \varepsilon_1$, go to iteration (k+1).

Part II

Calculate $E = L - 100\ (\sum_{i=1}^{M} P_{i,\ell} - SL_\ell)$

where $SL_\ell = \sum_{m=1}^{M} \sum_{n=1}^{M} B_{f(m)f(n)}\ P_{m,\ell}\ P_{n,\ell} + \sum_{n=1}^{M} B_{f(n)o} P_{n,\ell} + B_{oo}$

If $|E| \leq \varepsilon_2$, the procedure is finished and:

$$\begin{cases} \text{system } \lambda=\lambda_\ell \\ \text{sources generation level } P_i=100P_{i,\ell} \qquad i=1,..,N \\ \text{system losses } SL=100SL_\ell \\ \text{system load error}=E \end{cases}$$

If $|E| > \varepsilon_2$:

a) If ℓ=NS take $\lambda_{\ell+1} = \frac{\lambda_{\ell-1}+\lambda_\ell}{2}$, calculate corresponding $P_{i,\ell+1}$ i=1,..,N and stop as the step would be the last one, and write a message containing the values $\ell, \lambda_{\ell-1} \lambda_\ell$, E.

b) If ℓ<NS, calculate a new λ for the next step ($\lambda_{\ell+1}$), as follows:

$$\text{If } \sum_{i=1}^{N} P_{i,\ell} \neq \sum_{i=1}^{N} P_{i,\ell-1}, \quad \Delta\lambda_\ell = \frac{\lambda_\ell - \lambda_{\ell-1}}{\sum_{i=1}^{N} P_{i,\ell} - \sum_{i=1}^{N} P_{i,\ell-1}} E$$

and $\lambda_{\ell+1} = \lambda_\ell + \Delta\lambda_\ell$

Otherwise, $\lambda_{\ell+1} = \frac{\lambda_{\ell-1}+\lambda_\ell}{2}$

Go to step (ℓ+1).

Subroutine ECDIS2

1. Input

- sources to be allocated incrementally and their generation level (MW)

  $i=1,..,N$
  $G_1,..,G_N$

- sources generation limits (MW)
- cost curve slope and intercept for these sources
- system load error E_1 (MW)

  $E_1>0$ system generation should be increased
  $E_1<0$ system generation should be decreased

- initial incremental cost λ_1.

2. Output

- system λ (incremental cost)
- sources generation level P_i, $i=1,..,N$ (MW)

3. Subroutine Constants

$\varepsilon_1 = .001$ (hundred MW)

$\varepsilon_2 = .1$ (MW)

NS = 10

4. Computational Definitions

The procedure is similar to the one used in the subroutine ECDIS1, with the following changes:

- The system losses are disregarded and thus all coefficients B are 0 and therefore all SL's are 0.
- The constraint equation is:

$$100\left(\sum_{i=1}^{N} P_i\right) = L_1 + E_1$$

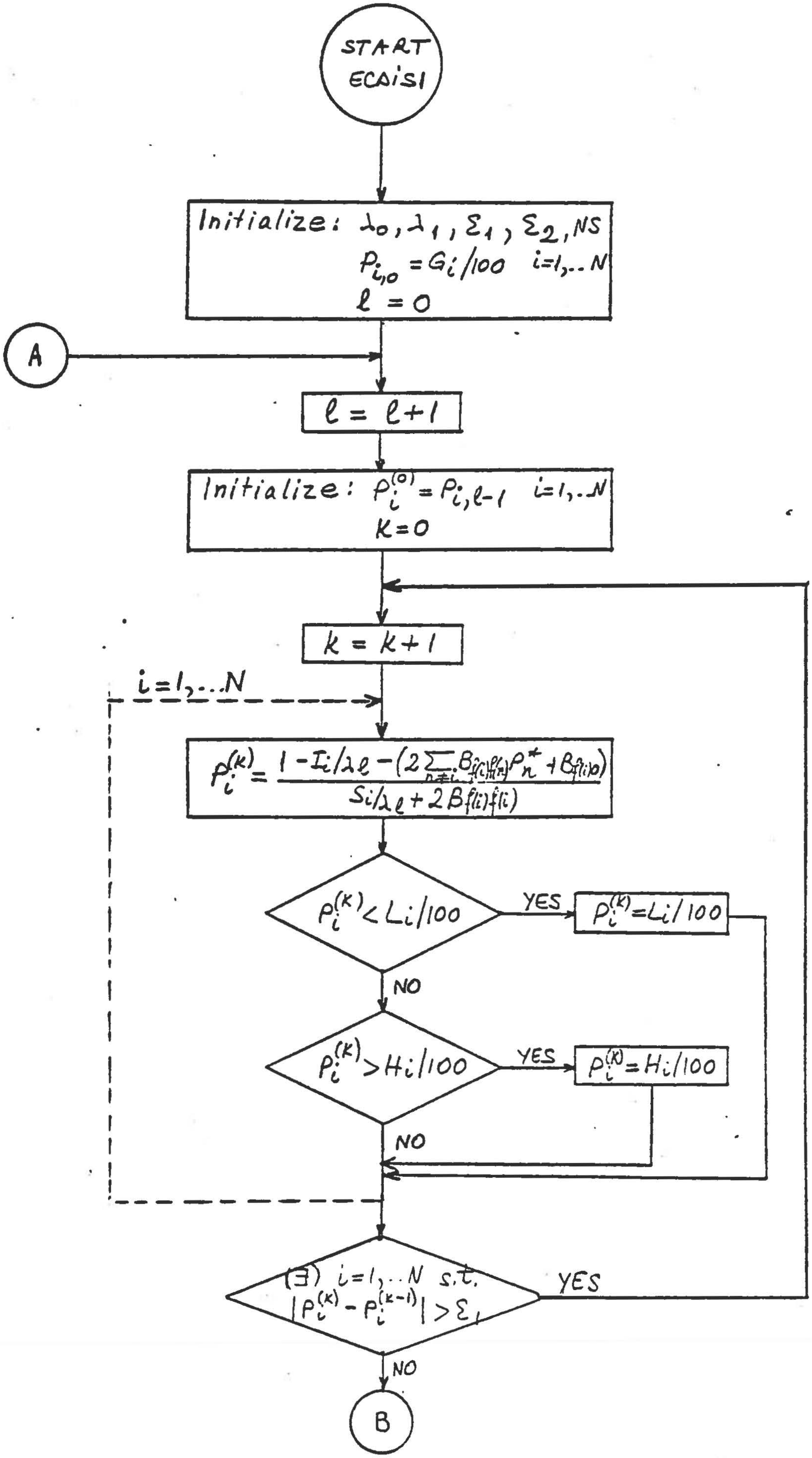
where L_1 is the sum of the initial generation of all sources available for incremental allocation:

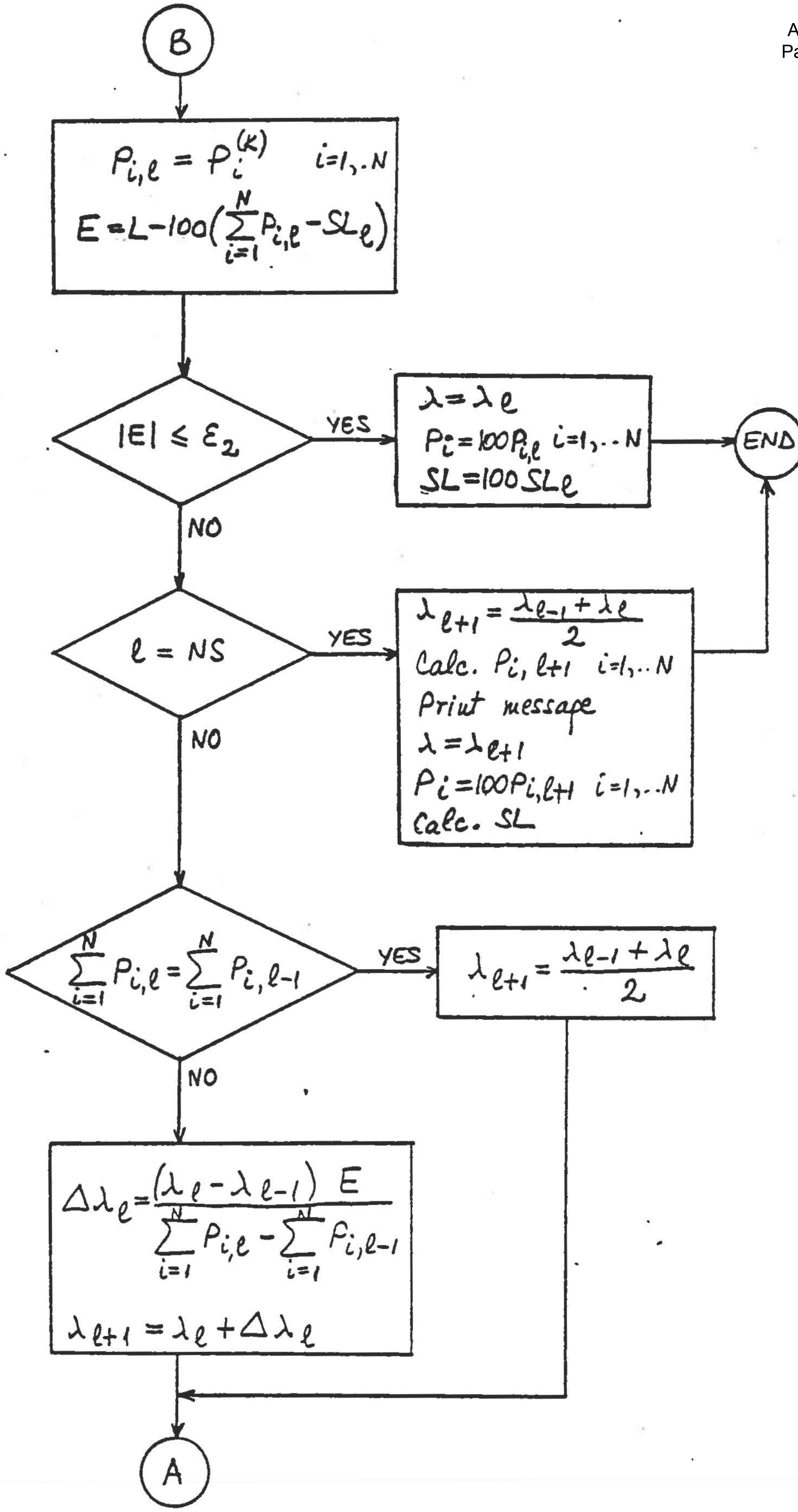
$$L_1 = \sum_{i=1}^{N} G_i$$

Consequently, the system load error E in Part II becomes:

$$E = L_1 + E_1 - 100 \left(\sum_{i=1}^{N} P_{i,\ell} \right)$$

5. Flowchart


START ECDISI
Initialize: $\lambda_0, \lambda_1, \varepsilon_1, \varepsilon_2$, NS
$P_{i,0} = G_i/100 \quad i=1,..N$
$\ell = 0$
A
$\ell = \ell + 1$
Initialize: $P_i^{(0)} = P_{i,\ell-1} \quad i=1,..N$
$k=0$
$k = k+1$
$i=1,...N$
$P_i^{(k)} = \frac{1 - I_i/\lambda_\ell - (2\sum_{n\neq i} B_{f(i)f(n)} P_n^* + B_{f(i)0})}{S_i/\lambda_\ell + 2B_{f(i)f(i)}}$
$P_i^{(k)} < L_i/100$
YES
$P_i^{(k)} = L_i/100$
NO
$P_i^{(k)} > H_i/100$
YES
$P_i^{(k)} = H_i/100$
NO
$(\exists)\ i=1,..N$ s.t. $|P_i^{(k)} - P_i^{(k-1)}| > \varepsilon_1$
YES
NO
B


B
$P_{i,\ell} = P_i^{(k)}$ $i=1,..N$
$E = L - 100\left(\sum_{i=1}^{N} P_{i,\ell} - SL_\ell\right)$
$|E| \leq \varepsilon_2$
YES
$\lambda = \lambda_\ell$
$P_i = 100 P_{i,\ell}$ $i=1,..N$
$SL = 100 SL_\ell$
END
NO
$\ell = NS$
YES
$\lambda_{\ell+1} = \frac{\lambda_{\ell-1} + \lambda_\ell}{2}$
Calc. $P_{i,\ell+1}$ $i=1,..N$
Print message
$\lambda = \lambda_{\ell+1}$
$P_i = 100 P_{i,\ell+1}$ $i=1,..N$
Calc. SL
NO
$\sum_{i=1}^{N} P_{i,\ell} = \sum_{i=1}^{N} P_{i,\ell-1}$
YES
$\lambda_{\ell+1} = \frac{\lambda_{\ell-1} + \lambda_\ell}{2}$
NO
$\Delta\lambda_\ell = \frac{(\lambda_\ell - \lambda_{\ell-1})\, E}{\sum_{i=1}^{N} P_{i,\ell} - \sum_{i=1}^{N} P_{i,\ell-1}}$
$\lambda_{\ell+1} = \lambda_\ell + \Delta\lambda_\ell$
A