Is Central Station Photovoltaic Power Dispatchable?

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IS CENTRAL STATION PHOTOVOLTAIC POWER DISPATCHABLE?

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ABSTRACT

A new operational tool for integrating a photovoltaic (PV) system into the utility's generation mix is introduced. The development and implementation of a new approach -- a dynamic rule-based (RB) dispatch algorithm is presented, which takes into account the problems faced by the dispatch operator during a dispatch interval and channels those into a rule base. The new dynamic dispatch requires forecasts of photovoltaic generations at the beginning of each dispatch interval. A Box-Jenkins time-series method is used to model the sub-hourly solar irradiance. This model is extended to yield forecast parameters which are then used to predict the photovoltaic output expected to occur at certain lead times coinciding with the economic dispatch intervals. The RB is introduced to operate either as a substitute for, or an aide to the dispatch operator. The RB gives one of 16 possible solutions as and when required. These solutions are written as rules which manipulate the non-committable generation to achieve an optimal solution. It is concluded that results depend on the time of the year and the specific utility. Also, the utility generating capacity mix significantly influences the results.

1. INTRODUCTION

Optimal dispatch of photovoltaic (PV) power, in its true meaning, is actually non-existent in the current state of the research on the integration of this relatively new technology into the utility's power grid. This fact is clearly portrayed in the literature available at this time. The most significant impact of central station PV power can be seen in the three following areas:

- Directly serving the load;
- Reliability service (equivalent to spinning reserve); and
- Load frequency control.

For a thermal plant, these functions are inherently built-in, but for a PV plant, with the present technology, it has not been possible to play all the above roles due to lack of control. The existing conventional generating units, through the use of AGC, are capable of operating under the dynamic response required to supply the random variations in system load. Such is not the case with central station PV plants. Frequent weather changes may translate into extremely high variations in power generations from the plant. If the plant is connected to the distribution system, this causes operational problems like **load following**, **spinning reserve requirements**, **load frequency excursions**, **system stability**, etc., which the conventional AGC system is unable to handle. This calls for modifications of the existing schedule and control algorithms to incorporate the random variations in PV output.

This paper deals with the development of a new strategy for dynamic economic dispatch that allows the control of PV plant generations and therefore, avoids the penalties because of load following and spinning reserve requirements and other related real-time operational problems.

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The need for definite control strategies becomes evident when one examines the role of PV plants at present. Until now, most researchers have used a static analysis of PV generations in the central station utility concept. A major disadvantage of the static approach is that, there is no way of knowing ahead of time the potential effects the high variations in PV generations might have on generations from the cycling units in the system. Because of this static approach, PV plant operation in power systems has essentially been limited to hourly system load modifications by PV output and then scheduling the conventional generations to supply the net load. In other words, PV generation is only used to get a modified unit commitment output [1,2,3]. The unit commitment programs generally provide the information on thermal, hydro and combustion turbine (CT) units scheduled for a period of 24 hours to a week. Besides, a production costing sub-program computes the cost of generation to supply the expected loads during the same period. The program is executed twice, once with PV power output and then again without the same. The difference in production costs revealed by these two runs, indicates the fuel credit attributable to the PV system. This approach has several disquieting characteristics. These are:

1. PV output over the day or week of the unit commitment period is simulated using *typical weather data* at the site. In other words, a particular set of data that is considered to be the general weather pattern at the site for a specific period of the year is used in this approach. This is likely to introduce large errors in the PV output estimation. While load forecasts during this period follow a particular trend and are generally considered accurate to a certain degree, the same cannot be said for the PV output. The reason is that, PV plant performance depends on the highly variable weather phenomena and are liable to extreme changes during the week. Weather forecasts as far ahead as one week can not be considered reliable. Therefore, the amount of uncertainty introduced into the unit commitment program output is considerably increased because of the presence of PV power.

2. With this approach, PV power is considered to be *forced* on the system. No care is taken to see how the operation of the PV plant might affect the base-load units. The latter are required to operate at the same level of generation throughout the day, in order to be most economic. Also, no care is taken to see whether there is enough cycling capacity available at any time during which the net load changes substantially because of the forced PV generations.

3. The penetration level (capacity rating of PV plant compared to total system capacity) of PV power is not well defined. Apparently, the phrase "the more the better" applies to this case. Increased PV generations causes increased fuel savings. Therefore, the larger the PV plant, the better or more economic it is for the entire system as a whole. But with increasing amount of PV power, there comes a situation when some conventional dispatch units will not be scheduled by the unit commitment (UC) program which otherwise would have been scheduled because the UC program is led to believe there is enough firm capacity. This change in the generation schedule is not acceptable because of uncertainties involved with PV plant operation and the potential severity in the system security because of loss of valuable spinning reserve. As mentioned in (1), PV power is only as reliable as the weather, and decommitting a unit means loss of valuable spinning reserve and possible regulating capacity for a number of successive hours. (Once a steam unit is brought down, it cannot be brought back up immediately). Considering this probable outcome, we are led to the contradictory statement that *PV penetration should be limited.*

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Judging from the above points, clearly the real-time operations perspective of the PV plant is ignored. An attempt is made in this paper to devise an algorithm that does everything that a standard AGC program accomplishes, with the additional capability of treating the PV plant as a dispatchable unit, comparable to the dispatch operation of a combustion turbine unit.

The problem of dispatching PV power under these circumstances, adds a new facet to the entire problem. First, the dispatcher has no knowledge about the amount of generation, which will be available at any dispatch interval. Secondly, actual observations at various PV sites in the Southeastern U.S. shows high amount of fluctuations in the solar irradiance within a 3-minute interval. This variation translates into constantly fluctuating PV generations posing a serious decision-making problem for the dispatcher. These problems can be resolved by using a **rule based** system, which will comprise of all the decision process of an expert dispatcher plus the speed of a computer processor. The new proposed methodology provides the following:

- A prediction of sub-hourly solar irradiance;
- An economic dispatch; and
- A decision support system.

2. PREDICTING PV OUTPUT AT SUB-HOURLY INTERVALS

In applications such as utility grid connected systems, it is important to be able to dispatch the PV output in the same fashion as any conventional generators, like coal and oil-fired units. That means the dispatcher has to have the information about the general availability of PV power plant 24 hours in advance (for unit commitment), and expected fluctuations in PV output in 10 minute time frame (for economic dispatch). The expected weather conditions of the next day, will determine the availability of PV power in the 24-hour time frame. However, for the economic dispatch considerations the prediction of PV output in 10 minute (or less) intervals is necessary. Failure to do so will cause the PV power to remain non-dispatchable and will inhibit its penetration in the utility grid.

A novel approach for the prediction of the solar irradiance in the sub-hourly time frame (3-10 minutes) by means of a Box-Jenkins [4] time-series analysis has been published in a previous work by the authors [5]. Thus only a concise summary of the technique is presented in this paper.

Some have suggested the use of satellite images for predicting PV output. But there is a problem with resolution and frequency. Satellite images provide snapshots of the sky over the contiguous U.S. (at least half of it) every 30 minutes. Such information may give a general idea about the cloud movement over a region (viz. a state or parts of it), but it does not address the localized phenomenon. It can only provide gross estimates about changes in insolation at a PV site. With the existing technology the satellite images may be used as an aide to time-series based short term forecasting, but by themselves they would not be sufficient to provide the data necessary for the sub-hourly forecast discussed in this paper.

2.1 A Time-series Model for Irradiance Prediction

The most fundamental time series models are the *autoregressive* model and the *moving average* model [4]. In the autoregressive model AR(p), the current value of the process is expressed as a linear combination of p previous values of the process and a random shock.

$$z_t = \varphi_1 z_{t-1} + \cdots + \varphi_p z_{t-p} + a_t \tag{1}$$

Equation (1) can be written as:

$$\varphi(B) z_t = a_t \tag{2}$$

where

$$\varphi(B) = 1 - \varphi_1 B - \varphi_2 B^2 - \cdots - \varphi_p B^p$$

In the moving average model MA(q), the current value of the process is expressed as a linear combination of q previous random shocks.

$$z_t = a_t - \theta_1 a_{t-1} - \ldots - \theta_q a_{t-q} \tag{3}$$

Equation (3) can be written as:

$$z_t = \theta(B) a_t \tag{4}$$

Where

$$\theta(B) = 1 - \theta_1 B - \theta_2 B^2 - \ldots - \theta_q B^q$$

The general mixed *autoregressive-moving average* model ARMA (p, q) is a combination of (2) and (4)

$$z_t - \varphi_1 z_{t-1} - \ldots - \varphi_p z_{t-p} = a_t - \theta_1 a_{t-1} - \ldots - \theta_q a_{t-q} \tag{5}$$

Writing (5) is the operator notation

$$\varphi(B) z_t = \theta(B) a_t \tag{6}$$

Equation (6) can only be used to model stationary processes where the roots of the polynomial φ(B) and θ(B) lie outside the unit circle. Non-stationary processes can be modeled by differencing the original process z_t to obtain a stationary process, w_t . Multiple differencing may sometimes be required in order to achieve stationarity. This results in an *autoregressive integrated moving average* ARIMA (p,d,q) model, which is expressed as:

$$\varphi(B) \nabla^d z_t = \theta(B) a_t \tag{7}$$

where ∇^d is the differencing operator of order d.

It is a well known fact that the hourly solar irradiance data presents a diurnal as well as an annual periodicity. To model such data in its raw form would mean using a seasonal ARIMA model which recognizes the dependence of a particular hour's data on the same hour of all the previous day's and all previous year's data. Needless to say, the dimensionality of this seasonal modeling appears to have unwieldy proportions. To make things less complicated, it becomes necessary to *pre-whiten* the solar irradiance data so that all periodicities may be stripped. The underlying principle is the recognition of the fact that the randomness found in the global solar irradiance data received on earth's surface is caused by changes in the cloud cover and the aerosol content in the air. A clear day's (cloudless sky) irradiance data may be estimated accurately by atmospheric parameterization [6], and is therefore deterministic in nature. It is the stochastic behavior of constant cloud movement which makes the radiation on a cloudy day difficult to predict. It was therefore decided to model the cloud cover, or in computational terms, the cloud transmissivity coefficients by an ARIMA (p,d,q) model of the form shown in equation 7 where z_t represents the transmission coefficients.

Forecast equations for cloud transmission coefficients are easily derived using the specific ARIMA (p,d,q) model which depends on the site and the period of the year. A reverse pre-whitening process yields forecast values for the solar irradiance.

3. A RULE-BASED DYNAMIC DISPATCH

Dispatchers (operators) have to make decisions regularly when they operate and control the power system. Even in the absence of unusual and emergency situations, many of the decisions are non-trivial in their nature. Therefore, a successful operation depends on the ability of the dispatcher to interpret information and to execute proper control. Today, the work of the system operator is eased in many ways. For example, a computerized control system can improve the interpretation of the vast amounts of data which are transmitted and collected in control centers. Application functions of various types also contribute to helping the dispatcher in the decision making process, but the requirement is that he must have the expertise or experience to use them.

An economic dispatch program is run at every 2-10 minute interval. The dispatcher has to work from the hourly committed dispatchable units and use standard procedures to allocate generation levels, maintain the right amount of regulating capacity, maintain the system frequency, maintain the area control error at zero in case of interconnected systems, bring up fast start-up units like peaking hydro or gas turbines in case of emergencies, etc.

It is conceivable to represent the knowledge of the dispatcher as a **rule-based** computer algorithm. The decision making process of the dispatcher renders itself perfectly to sets of "If-Then" rule structures for use by a **rule-based system**. This rule base (RB) approach to economic dispatch becomes almost a necessity when the dispatch algorithm has to deal with the operation of a photovoltaic system.

3.1 A Rule Base Replacing the Dispatcher

A rule base will be defined as an intelligent combination of procedures that uses knowledge and inference techniques of the human expert to solve problems in an algorithmic manner. In narrow problem domains, the rule base can provide high performance, equalling or even exceeding that of human individual experts.

In the proposed dynamic economic dispatch incorporating PV, a rule base is introduced to operate, either by itself or in tandem, with a conventional economic dispatch algorithm. The functions of the two are coordinated by another algorithm which overlooks the flow of information and records them. This functional relationship between the three computer program modules are shown in Figure 1. The operations of the economic dispatch and the rule base are coordinated by the module called DRIVER. The module makes sure that there is enough reserve margin as required by the system. It computes the contributions from all non-committable sources, computes artificial minimum and maximum limits dictated by response rates of thermal units and passes the information to the ECONOMIC-DISPATCH module. The DRIVER then, receives back information on the mismatches between the possible dispatchable generation under constraints and that required by the system. This is then passed on to the RULE-BASE module which makes the necessary decisions to correct the situation. The RB at this stage communicates directly with the ED module.

At this time, it is worthwhile to examine the nature of the problem introduced by the presence of PV power in the mix before rules are established for an RB approach to the solution.

PV Dispatch

The treatment of PV generation is considered, in this economic dispatch approach, to be similar to that of combustion turbines (CT). The essential similarities are the fact that CTs can be brought on-line within a very short period of time whenever there is need for extra capacity, and they can be backed off whenever desired. Proceeding along those lines, provided PV power is forecasted to be available at say 100 MW, the PV plant may be controlled to produce anywhere from 0 to 100 MW as and when required. Dissimilarities exist in the operation of the two plant types though. Whereas, a CT plant operates on a low capacity factor (average capacity of operation over the rated capacity) because of high cost of fuel, a PV plant is expected to run on as high a capacity factor as possible in order to compete favorably against conventional thermal units. Therefore, whenever the PV plant is available, it will be required to not only supply the peak loads, but also intermediate loads.

Unquestionably, the single most important parameter that is the cause of PV dispatch problems is the response rate of thermal units. During dispatch, the fundamental constraint becomes:

At any time t, expected power generation required from the thermal generators must equal expected load at t minus the sum of generation from non-conventional sources minus the PV output at t.

$$G_t - G_{t-1} = D_t - D_{t-1} + L_t - L_{t-1} - (C_t - C_{t-1}) - (H_t - H_{t-1}) - (PSH_t - PSH_{t-1}) - (IC_t - IC_{t-1}) - (PV_t - PV_{t-1}) \quad (8)$$

implying:

$$\Delta G_t = \Delta D_t + \Delta L_t - \Delta C_t - \Delta H_t - \Delta PSH_t - \Delta IC_t - \Delta PV_t \quad (9)$$

where G_t = the total thermal generation at time t
G_{t-1} = the total thermal generation at time t-1
D_t = the total demand at time t
D_{t-1} = the total demand at time t-1
L_t = the total losses at time t
L_{t-1} = the total losses at time t-1
C_t = the total combustion turbine generation at time t
C_{t-1} = the total combustion turbine generation at time t-1
H_t = the total hydro generation at time t
H_{t-1} = the total hydro generation at time t-1
PSH_t = the total pumped-storage hydro generation at time t
PSH_{t-1} = the total pumped-storage hydro generation at time t-1
IC_t = the total interconnected power flow at time t
IC_{t-1} = the total interconnected power flow at t-1
PV_t = the total photovoltaic generation at time t
PV_{t-1} = the total photovoltaic generation at time t-1

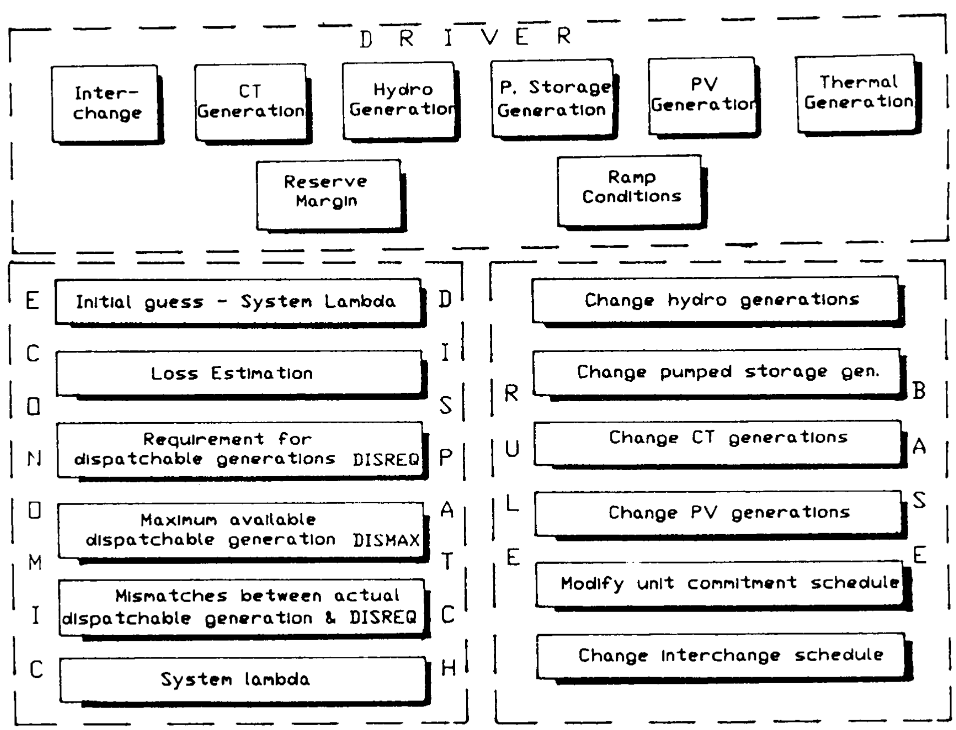

Figure 1. Functions of Three Program Modules

Normally, differences in losses and other load-generation mismatches in the absence of PV power are easily picked up by cycling (load following) units and the system maintains a matched load condition. With PV power on the other hand, large variations in PV output can cause the thermal plants to reach their response limits before load matching constraint is met. Therefore, two conditions might arise:

- *Thermal generation increase not possible in the dispatch interval.*

  This situation may arise because of a sudden drop in PV power in the mix, causing the thermal generators to attempt to make up the loss. Using the up-ramp response constraint of each cycling thermal unit, the total system response capability (regulating capacity) in the "up" direction should be greater than or equal to the change in generation required of the units. Mathematically,

$$\frac{1}{100}\sum_i \Delta T \gamma_{ri} P_{it-1} \geq \Delta G_t \tag{10}$$

  where ΔT = dispatch interval
  P_{it-1} = MW output of unit i at interval t-1
  γ_{ri} = response rate of unit i in the raise direction (%/min)
  Violation of equation 10 implies corrective action has to be taken to reach optimality.

- *Thermal generation decrease not possible in the dispatch interval.*

  This situation is brought about when there is a sudden increase in PV generation in the mix possibly by movement of clouds away from the area. The thermal generators are expected to back-off part of their generations (unload) in order to accommodate the additional PV power. Once again, the response rate of the thermal generators plays an important role, this time in the "lower" direction. According to the down-response rate of each unit, the total system response capacity in the lower direction should be greater than or equal to the change in generations required from the generators. Mathematically,

$$\frac{1}{100}\sum_i \Delta T \gamma_{li} P_{it-1} \geq \Delta G_t \tag{11}$$

  where γ_{li} = response rate of unit i in the lower direction (%/min.) Violation of equation 11 once again implies corrective action has to be taken, by the dispatcher.

The corrective actions are channeled into "rules" or "if-then" logic structures. These rules are described next.

3.3 Rules in the Rule Base

Problems in operation require corrective actions so that the system may be brought back to an optimal state. The following is a sample of the set of rules written for the RB system. Each rule-set is in turn a combination of a number of rules as can be seen in figure 2.

```
Comment Check to see if a hydro plant is present in the generation mix.
If (NUM_HYDRO = 0) then
    begin
    Comment No hydro plant is present. Therefore, set flag to false
            and go to rule 6.
    FLAG2 := false;
    end
else
    begin
    Comment Hydro plant is present in the mix. Search for units which are down.
            If found, locate the unit with a capacity which matches the MW amount
            of increase required by the system.
    UNIT_FOUND := 0;
    NUM_LOOP := 1;
    N := NUM_HYDRO;
    While (N > 0) do
        begin
        If (UP_HYD_STATUS(NUM_LOOP) = 1) then
          begin
          Comment The hydro unit is up. Check the next one.
          NUM_LOOP := NUM_LOOP + 1;
          N := N - 1;
          end
        else
          begin
          Comment Check for up-time and down-time constraint violations.
          call UNIT_VIOLATE (NUM_LOOP, VIO_FLAG);
          If (VIO_FLAG = true) then
            begin
            Comment Constraint violated. Check next unit.
            NUM_LOOP := NUM_LOOP + 1
            N := N - 1;
            end
          else
            begin
            UNIT_FOUND := UNIT_FOUND + 1;
            CONTRIB (UNIT_FOUND) := MAX_CAP (NUM_LOOP);
            NUM_LOOP := NUM_LOOP + 1;
            N := N - 1;
            end
          endif
          end
        endif
        end
    end
endif
If (UNIT_FOUND = 0) then
    FLAG2 := false;
else
    begin
    Comment Prioritize the hydro units selected.
    call PRIORITY (CONTRIB, INC_AMOUNT, UNIT_ORDER)
    Comment The order of the selected hydro units according to descending order
            of capacity is stacked in the UNIT_ORDER stack. This stack is popped
            sequentially to schedule the units.
    TOTAL_CAP := 0;
    While (TOT_CAP < > INC_AMOUNT) do
        begin
        UNIT := pop (UNIT_ORDER);
        TOTAL_CAP := TOTAL_CAP + MAX_CAP (UNIT)
        Comment Upgrade status of the unit to "up" mode.
        STATUS (UNIT) := 1;
        end
    end
endif
```

Figure 2. Rule-Set Number 5

RULE-SET 1 *If thermal units are unable to pick up the increased net demand of the system, and if the PV plant was operating at below maximum capacity in the last interval of the dispatch, then increase PV generation.*

RULE-SET 2 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 1 is not satisfied, then increase hydro generation.*

RULE-SET 3 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 2 is not satisfied, then increase pumped storage hydro generation.*

RULE-SET 4 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 3 is not satisfied, then increase combustion turbine generation.*

RULE-SET 5 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 4 is not satisfied, then start-up unscheduled hydro unit(s).*

RULE-SET 6 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 5 is not satisfied, then start-up unscheduled pumped storage unit(s).*

RULE-SET 7 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 6 is not satisfied, then start-up unscheduled CT unit(s).*

RULE-SET 8 *If thermal units are unable to pick up the increased net demand of the system, and if RULE-SET 7 is not satisfied, then buy unscheduled interconnected power.*

RULE-SET 9 *If thermal units are unable to unload the extra generation because of a decrease in net system demand, then decrease CT generation.*

RULE-SET 10 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 9 is not satisfied, then decrease pumped storage hydro generation.*

RULE-SET 11 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 10 is not satisfied, then decrease hydro generation.*

RULE-SET 12 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 11 is not satisfied, then shut down scheduled CT unit(s).*

RULE-SET 13 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 12 is not satisfied, then shut down scheduled pumped storage hydro unit(s).*

RULE-SET 14 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 13 is not satisfied, then shut down scheduled hydro unit(s).*

RULE-SET 15 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 14 is not satisfied, then decrease tie-line interchange flow.*

RULE-SET 16 *If thermal units are unable to unload the extra generation because of a decrease in net system demand and if RULE-SET 15 is not satisfied, then decrease photovoltaic power.*

The set of rules 1 through 8 are valid for the situation when there is a significant reduction in the non-committable generations causing the thermal generators to attempt to pick up generation. Response limitations of thermal units therefore require other measures to be taken. Rule-set 1 receives the highest priority as logical reasoning dictates that PV power use ought to be maximized. Therefore, it will be the purpose of the RB to supervise the presence of maximum possible PV power which is the most favorable scenario from the production costs point of view. (Here production cost implies fuel and operating costs, and does not include capital cost). Although, the rules are written in FORTRAN, the style of a declarative language is used to represent the logic.

Rule-set 2 through 4 are similar although concerning different unit types. Rule-set 5 through 8 are apparently violations of the optimal solution given by the unit commitment program. There is nothing so alarming about this violation. The only concern under this action, that of departure from optimality, is quite unwarranted, because the system is already in a sub-optimal state considering the fact that the thermal units are not able to follow the economic trajectory. The only legitimate concern under this situation should be that starting up unscheduled units may violate some constraints, e.g., minimum up-time or minimum down-time requirements. The rules to be established are therefore required to examine these constraints before starting unscheduled units. As for start-up time itself, the units to be considered by the RB for start-up are fast-start units, like peaking hydro, pumped storage hydro and combustion turbines, which need little warm-up time. Figure 2 shows the logic for rule-set 5. For avoiding repetition of similar characteristics, other rule-sets are not shown. The logic for these sets of rules is centered on locating the optimal capacity unit which matches the generation increment requirement INC_AMOUNT. If that is not possible, multiple units are searched for, whose combined capacity adds up to the variable INC_AMOUNT. A sub-program called PRIORITY locates these units and "pushes" these units into a "stack", with the highest priority unit residing at the top of the stack. A sequential "pop" operation then brings out these units from the "stack".

Rule-set 8 is somewhat different from other rules, as it involves buying unscheduled power from interconnected systems. This action advocates caution because it involves more than one area. Area control error (ACE) problem is one criterion that must be looked into before scheduling any interchange over a tie-line.

The RB follows these sets of rules sequentially whenever there is not enough regulating capacity in the system. At any point in time, a part of any set of rules may be satisfied, in which case a coordinated decision is taken. For example, during dispatch operation, it was found that thermal generation could not be increased any further to match the total load demand. The RB finds a hydro unit to be scheduled which can only satisfy part of the increase in generation required. None of the other rule-sets 1 through 7 can be satisfied. In this case, the RB will schedule interconnected power to make up the rest of the increment. In situations like these, human interaction produces delay and may take longer than the dispatch interval itself. The RB provides solutions within seconds.

It should be noted that a tie-line may be receiving power from a number of interchange companies. The sub-program ACE checks for NERC (North-American Electric Reliability Council) regulation violations related to area control error. The tie-line bias [7], should be such that the ACE is brought back to zero within the dispatch interval.

Rule-sets 9 through 16 employ inverse logic to what is used in rule-sets 1 through 8. For example rule-set 14 is concerned with shutting down a scheduled hydro unit as compared to rule-set 5 which is applied for starting up unscheduled hydro units. The set of rules effecting change in the photovoltaic operation in the scenario of the presence of "unloadable generation" is given a low priority. Following along the same reasoning as before, one would like to maintain as much PV generation in the system, until it comes down to a "last resort" to reduce the PV generation level.

4. CASE STUDY

This section presents results of a case study using the PV output forecast strategy and the rule based dispatch algorithm. The data used for the study represents a location in Virginia. This is a typical location in the southeastern United States and has moderate weather throughout the year. The PV plant used in the simulation is rated at 750 MW dc.

The generation mix used for the study is derived from the EPRI synthetic utility system [8] for southeastern U.S. modified by personal communication with a number of utility operations personnel in the region. This generation mix consists of 8501 MW of steam (thermal) units and 591 MW of combustion turbines. The system peak load is considered to be 7432 MW. The results presented in this section are targeted toward bringing out the differences in a power system with and without a photovoltaic power plant.

4.1 Continuous Simulation Run

For the purpose of presenting the results, a continuous simulation procedure was followed. The algorithm of this process is shown in Figure 3. At the outset, parameters such as, generator data, generator schedule, dispatch interval, etc., are read in. PV output forecasts are issued only if the interval of simulation falls within the daytime hours. After reading in the interval's load demand, an economic dispatch calculation is performed. In case of any dispatch problems, e.g., inadequate regulating capacity or spinning reserve, the rule-based system takes over and matches the generation and demand maintaining sys-

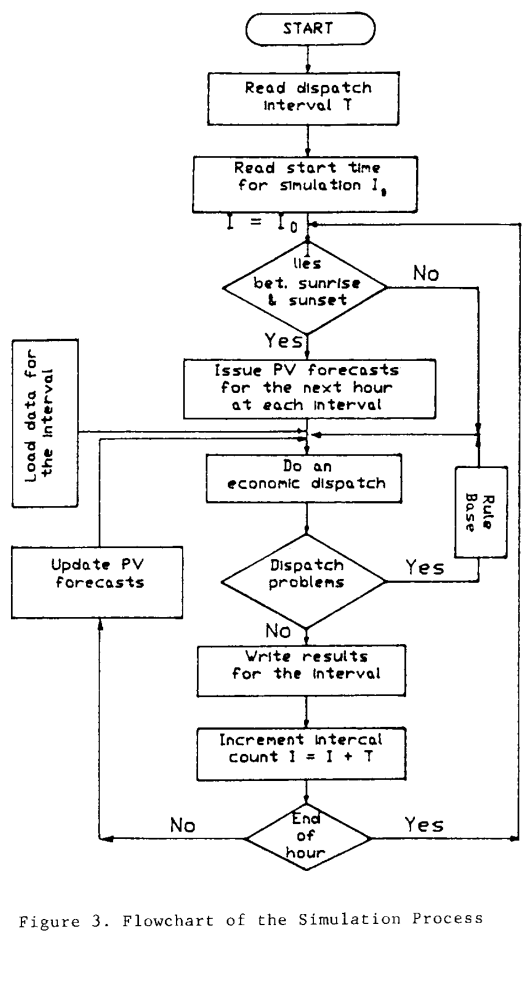

Figure 3. Flowchart of the Simulation Process

tem security, and an economic dispatch calculation is redone. When there are no problems, the results are written out for the interval and the time counter is incremented by one interval. If the time coincides with the end of the hour, program control is handed back to the PV output forecast routine which issues new forecasts for the upcoming hour of simulation. If on the other hand, the time is within the hour, PV generation forecasts are updated with the newly available actual irradiance in the last interval before control is transferred directly to the economic dispatch program.

4.2 Generator Information

It should be mentioned here that only the dispatchable thermal units belonging to the synthetic utility are included in the optimization process. The base load units are supposed to run almost throughout the day and are therefore considered non-dispatchable for all practical purposes.

4.3 Load Data

Load demand data at 30 second interval are available from a Virginia utility. These are used to create an hourly load data (for generation scheduling purposes) and a sub-hourly load data base (for the dynamic economic dispatch program). The sub-hourly data consists of load demands at every 3 to 10 minute intervals. Figure 4 shows the sub-hourly load demand and PV plant generations for a sample day in the month of January. This day is particularly selected to show the variable nature of the PV generations. Such extreme variations in PV output may occur during sudden movement of thick, dark clouds covering the sun for several minutes before moving away again. It should be mentioned here that the figure shows only the dispatchable load. In other words, the base load is subtracted from the total load.

4.4 Simulation Results

A graphical representation of the net effect of having a PV plant in the generation mix is also shown in Figure 4. The particular feature shown in the figure is the effect on the dispatchable thermal generations during the entire 24 hour period. Also shown in the figure are the load profile and the photovoltaic generation on the same scale. The thermal generations follow the load (transmission losses not shown in the figure) consistently until the PV plant starts generating power. Dispatch problems that cannot be handled by the thermal units are picked up by combustion turbine units as shown in Figure 5. As seen here the inclusion of PV generation (and the associated fluctuations) may cause the CT's to stay on longer beyond the normal turning off cycle after 9 AM. Also some CT's have to be started earlier to cover the (late afternoon) loss of PV generation. Such operation of CT's would not put any undue pressure on their performance because the total number of start/stops would not change significantly.

Shown in Table 1, is a list of the system regulating capacity violations during the test day. The term "regulatory capacity violation" takes a special meaning in the context of the PV-integrated operating strategy discussed in this paper. Several power companies in the southeastern United States, as a part of their interchange agreements, are required to maintain a spinning reserve of some (usually under 5) percentage of peak load and some (usually under 10) percentage of the largest unit on-line. For example, Carolina Power and Light Company maintains a spinning reserve equivalent to 4% of the expected peak for the day and 8% of the largest unit on-line. For the system considered in this paper this would translate to a spinning reserve of (0.04 x 7432 + 0.08 x 900) 369.3 MW. Therefore more than half of the largest drop of PV output (638 MW from Table 1) can be covered by the spinning reserve. However, as we perceive the PV fluctuations to be routine occurrences, we do not expect these to be covered by the spinning reserve as traditionally determined and maintained. It is possible that the inclusion of PV output fluctuations in the spinning reserve calculation process may result in different reserve requirements. So in this paper we want to deal with the PV fluctuation problem outside of the spinning reserve considerations. Thus the term "regulatory capacity violation" represents the inability of the thermal units to ramp up or down fast enough to cover the PV-induced fluctuation.

Also evident from the table are the reasons of the violations which may be PV induced or otherwise. These violations occur because of inadequate generation capacity response in the system during times when the net load varies by a large amount during two successive intervals. Net load is derived from the actual load minus the noncommittable (CT, hydro, pumped storage and interchange) generations minus the PV generations (if present). In columns 2 and 3 are shown the total number of thermal units which have either reached their minimum limit or maximum limit set by their response

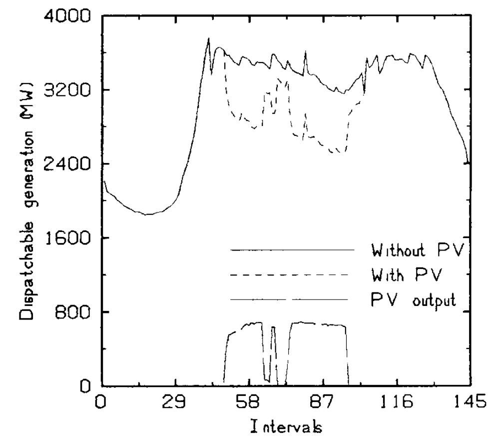

Figure 4. Sub-hourly(10-minute) Generation and Photovoltaic Output

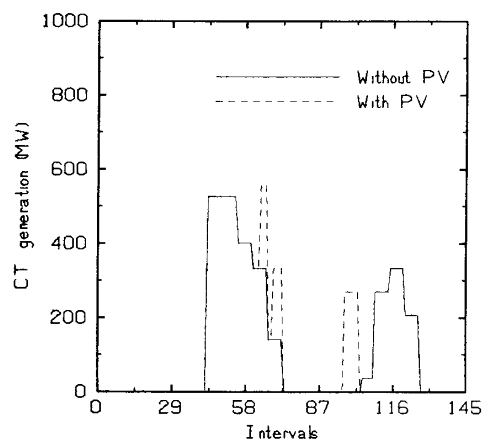

Figure 5. CT Generation with and without PV (Dotted lines show additional needs)

TABLE 1. Summary of System Regulating Capacity Violations

Time	Thermal Units Affected		Remarks
	CASE I	CASE II	
6:20 AM	3	3 (0[1]) (209[2])	No system problem
6:30 AM	1	1 (0) (200)	No system problem
6:50 AM	3	3 (0) (175)	No system problem
7:10 AM	7	7 (0) (120)	No system problem
8:10 AM	0	12 (416) (-59)	No system problem
8:20 AM	0	2 (136) (+3)	No system problem
10:40 AM		20 (-622) (-13)	Ther. load prob. in Case II
11:30 AM	0	20 (-634) (-63)	Ther. load prob. in Case II
12:20 PM	0	14 (360) (-67)	Ther. unload prob. in Case II
1:20 PM	7	5 (-9) (258)	No system problem
4:10 PM	0	21 (-638) (-4)	Thermal loading problem
4:20 PM	0	1 (0) (43)	No system problem
5:20 PM	18	18 (0) (411)	Thermal loading problem
6:10 PM	2	2 (0) (32)	No system problem

[1] MW change in PV generation from last interval; (+ => increase)
[2] MW change in load demand from last interval; (+ => increase)

rates. Also shown in column 3 within parentheses, are the changes in PV generations from the previous interval and the changes in actual loads from the previous interval. It is seen that only for extreme variations of PV plant output does the system experience loading or unloading problems. Other than that, the only cases when the system might have problems are when the load itself varies during the interval, by a large amount.

Table 2 gives a one-day summary of the operation of the power system with and without the addition of the PV plant. Total daily dispatchable thermal generation is reduced by 6.7% (4891 MWhr) with the addition of the 750 MW PV plant. On the other hand, CT picks up by 18.4% (510 MWhr). The PV plant operates with an availability factor of 58.4% considering 10 hours of sunshine on that day. The daily total spinning reserve is increased somewhat and the production costs fall by about 3.5% indicating a saving of more than $60,000 during the day. Here production costs include fuel and operating costs, no capital costs. The extra operation time seen by the combustion turbines in the absence of hydro or pumped storage generators is evident from the statistic on unit-hrs of operation time in the two cases.

TABLE 2. One-day Summary of System Operation

Parameter	No PV	With PV
Dispatchable generation	72757.50 MWhr	67866.24 MWhr
CT generation	2772.00 MWhr	3282.00 MWhr
PV generation	0.00 Whr	4381.54 MWhr
Pump. stor. generation	0.00 MWhr	0.00 MWhr
Hydro generation	0.00 MWhr	0.00 MWhr
Interchange	0.00 MWhr	0.00 MWhr
Spinning reserve	19144.49 MWhr	19267.19 Whr
Losses	3596.50 MWhr	3596.50 MWhr
Production costs	$1,725,526.90	$1,664,892.80
CT schedule	76 (Unit-hrs)	83 (Unit-hrs)
Hydro schedule	0 (Unit-hrs)	0 (Unit-hrs)
Pump. stor. schedule	0 (Unit-hrs)	0 (Unit-hrs)
Interchange schedule	0 (Unit-hrs)	0 (Unit-hrs)

4.5 Effect of PV Penetration

An important factor to be considered in the integrated operation of PV plants and conventional generating units is the effect of the PV plant rating as a fraction of the system capacity on the overall production costs which include fuel and operating costs. This is shown in Figure 6. In the figure, each percent of penetration represents 56.5 MW of generating capacity. The fact that production costs decrease with each additional penetration of PV plant is evident in the figure. Also featured in the figure is the fact that the costs level off after the penetration reaches a certain limit. The limit in the case study is found to be 13.27%. Beyond this point, system operational problems make it more expensive than the base case, to run a PV plant. This finding seems to be in-line with an upper limit of 16.8% of PV penetration (before benefits starts to decrease) reported by Khallat and Rahman [9].

5. SUMMARY & CONCLUSIONS

This paper has put forward a new operational tool for integrating a PV system with the utility. It is recognized at the outset, that much of the existing research concentrated on the central PV system and its operations have concluded that technical problems in PV operation will override any value or credit that can be earned by a PV system, and that penetration of a PV plant in the utility will be severely limited. These are real problems and their solutions are sought in this paper. The following points are believed to be the major obstacles that are plaguing the cause of PV systems, and for that matter, all renewable sources which depend on the weather or any random phenomenon. These are:

- At present, the PV generations, if any exist in the generation mix, are handled in a **static** manner in utility operations. The amount of uncertainty introduced into the unit commitment output with this approach, is considerably increased because of the presence of PV power.

- With the static approach, PV power is considered to be forced on the system. No care is taken to see whether the PV plant might be generating during a period of time when the base load units are operating. The latter are required to operate at the same level of generation throughout the day, in order to be most economic. Also, no care is taken to see whether there is enough cycling capacity available at any time during which the net load changes substantially because of the forced PV generations.

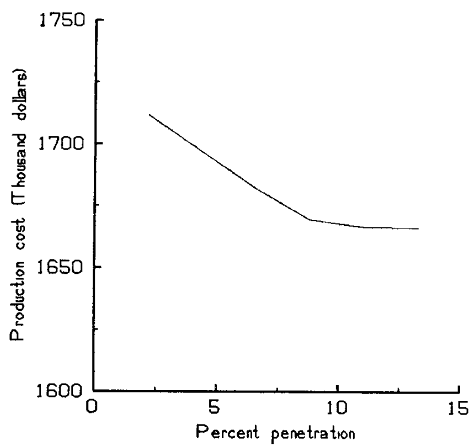

Figure 6. Effect of PV Penetration on Production Cost

This paper dealt mainly with the development and implementation of a new approach -- a dynamic rule-based dispatch algorithm which takes into account the major problems faced by the dispatch operator during a dispatch interval and channels those into a data base for use by a rule-based (RB) system.

The new dynamic dispatch requires forecasts of photovoltaic generations at the beginning of each dispatch interval to build a more realistic scenario. A Box-Jenkins time-series method was used to model the sub-hourly solar irradiance. This ARIMA model is extended to yield forecast equations which are then used to predict the photovoltaic output expected to occur at certain lead times coinciding with the economic dispatch intervals. The forecasts were found to fairly accurate and reliable.

In the rule-based dispatch algorithm that was developed in this paper, the rule-based system is introduced mainly to operate as an aide to the dispatch operator. It was found that inclusion of PV generation adversely affected the response limitation of thermal units. The problem was:

- Thermal generations were not able to respond quickly enough and maintain the economic trajectory as dictated by the unit economics and the net load.

The RB gives one of 16 possible solutions as and when required. These solutions are written as rules which manipulate the non-committable generation to achieve an optimal solution. The RB during its operation overlooks the fact that the PV generation are kept at the maximum level possible under all constraints. The case study revealed that the thermal generating units which are scheduled by the unit commitment are able to absorb most of the small to medium variations present in the PV generations. In cases of large variations during a single interval, for example, when the PV plant starts up from zero to a substantial amount in the morning, or when the plant shuts-off in the evening, the thermal generators reach their response limits before they can reach their maximum or minimum generation, thus causing mismatches in the load and generation. The mismatches are then picked up by the non-committable sources of generation (in the case study, combustion turbine units only), comprised of pumped storage units, hydro generation plant, or by interconnection tie-lines. If none of these are sufficient, changes are made in the PV generation schedule.

The effect on spinning reserve is markedly present during high variations in PV plant output. In the morning when the PV plant starts up, there is a sudden decrease in thermal generation which contributes to an increase in the spinning reserve. This is beneficial to the system because, the time of this PV plant start-up coincides with the morning load pick-up and therefore, the system would experience a potential reserve shortage without PV at this particular time. The situation reverses in the evening when the PV plant shuts off, and the load is also dropping significantly, so that the thermal units would have to pick up generation, thus reducing the reserves.

The case study revealed that during a typical single day's operation:

1. thermal plant generation was reduced by 6.7%,
2. CT generations picked up 18.4%,
3. the PV plant operated with an availability factor of 58.4%,
4. total spinning reserves increased insignificantly,
5. production costs fell by 3.5%, indicating a saving of $60,000 during the day, and
6. the worst situation occurred when the demand decreased, but at the same time, the PV generations increased substantially from one interval to another and vice versa.

The results obviously depend on the time of the year and the specific utility. The time of the year information is reflected in the load demand profile. Most utilities in the U.S. have single peaks in summer and double peaks in winter. Also, the time of the peak load occurrence, varies with season. The utility generating capacity mix influences the results a great deal. A utility with a generation mix having a combination of a number of non-committable plant types, for example, pumped storage, CT, hydro, and interconnection, would incur lower production costs since the extra non-committable generation required because of the presence of PV could be shared by all the plant types.

For the utility selected in the case study, penetration of PV was limited to 13.27% before operating mismatches were no longer possible to be resolved. Once again, the penetration is a function of the utility and the location.

The loss of load probability (LOLP) of a power system is calculated based on the expected outage rates of generating units. As we have seen the inclusion of the PV arrays may cause the CT to run longer than normal thereby affecting their availability. Also there are no published statistic on the availability of PV arrays. These two unknowns need to be quantified in order to compute the LOLP of a PV-integrated power system.

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Discussion

A. W. W. Cameron Retired,(London, ON, Canada): The dispatching problems associated with photovoltaic generation could be alleviated in some localities by the load-management technique of encouraging direct solar heating of buildings, especially by economical state-of-the-art systems using the masonry of a building as heat storage [A].

Where the direct electric heating of buildings is popular, the electric load relief by a given area of solar heating panels is in the range of five times the power supplied by the same area of photovoltaic cells, for the same clarity of sun. Moreover, where Solar heating is spread over a load area, the "passing-cloud" condition produces a load ripple over the area: when good heat storage is incorporated with the Solar heating panels, the fluctuation may not be noticeable.

The same applies where heat-pumps have been popularized, as has been found a useful load-management measure in some areas. However, with heat-pumps the electrical equilavent of solar heating is about halved on the average.

These remarks should not be taken as disputing the value of photovoltaic generation, but rather as facilitating its use by mitigating operating problems, and encouraging utilization of Solar energy by all means.

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[A] U.S. Patent 4 469 087, September 4, 1984.

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B. H. CHOWDHURY and S. RAHMAN. The authors would like to thank Mr. A. W. W. Cameron for his discussion of our paper. He contends that dispatching problems associated with photovoltaic generation could be alleviated in some localities by encouraging direct solar heating of buildings. We did not attempt to discuss the end use of electricity in our paper. We only looked at the effect of intermittency on dispatchability of a power system which includes photovoltaics. Therefore, if there is direct solar heating of buildings, the PV generated electricity would be used for something other than space heating, and the problems of intermittency would therefore, be shifted to some other application. While the "passing cloud" conditions would not significantly affect the solar heating applications, it would continue to cause the dispatchability problems associated with photovoltaic electric applications as we have discussed in the paper.

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