Cost-Effectiveness of Photovoltaic Generation In A Transmission-Constrained Load Area of An Interconnected System

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Abstract: Electric power systems of today are experiencing a difficulty of constrained transmission lines, which have severely limited transfer capability between interconnected regions. The problem is more compounded by such factors as difficulty in obtaining rights-of-way, the strong environmental movement, public protest against the construction of additional transmission facilities, and the resulting inability to expand the constrained system. All of these factors are forcing the utility planners and third parties alike to search for other viable alternatives to meet the uncertainly growing load in their planning regions or at least to be able to compete effectively in the growing electricity market. The present study examines and evaluates the applicability and cost-effectiveness of Photovoltaic (PV) generation in a transmission-constrained load area of a two-area interconnected system with limited transfer capability.

Keywords: Photovoltaic Generation, Power System Economics, Dispersed Generation, Transmission-Constrained Interconnected System, Limited Transfer Capability.

I. INTRODUCTION

The electricity industry in United States has evolved in a vertically integrated structure. It was more economic for utilities to build a few large central power stations and then deliver that energy through the interconnected transmission and distribution systems to customers than to install many smaller generators closer to customer sites. This had spurred the construction of many large power stations with high efficiency, which were located far from customer sites. A corollary result was the construction of transmission and distribution facilities to connect these generating sources to the loads.

However, the steady and constant load growth that has sustained the construction of larger power generating stations in the past has slowed down since the economies of scale have been exhausted. The costs of transmission and distribution systems are taking an increasingly larger portion of the utility capital investment today. The Public Utility Regulatory Policies Act (PURPA) of 1978 has opened up competition in the generation sector by allowing Qualifying Facilities (QF) to generate electricity and sell it to once-monopolistic utilities. Competition in generation sector was heightened by the Energy Policy Act (EPAct) of 1992. In addition to allowing new wholesale generators, EPAct establishes a federal policy to make the nation's transmission system accessible to all generators. Under new Federal Energy Regulatory Commission (FERC) rules, utilities are required to open up wholesale transmission services to third parties. Electric utilities not only face competition on the generation front, but also have to allow their transmission system to be used by competitors to facilitate such competition.

Moreover, present electric system networks are experiencing the difficulty of constrained transmission lines with limited transfer capability. Due to various obstacles, such as difficulty to obtain rights-of-way, environmental movement, public protests, and higher cost of facility construction, it becomes much more difficult to construct new transmission facilities or to reinforce the existing congested ones. Increased competition, constrained transmission lines with limited transfer capability, technological advances of newly emerging generation resources, and strong environmental movement in all sectors of the economy are important factors for electricity enterprises to consider in their planning activities. One new important development is the application of dispersed generation (DG) to meet forecasted load growth, particularly the application of Photovoltaic (PV) generation.

II. PROBLEM FORMULATION

The present study considers a two-area system – a larger area connected to a smaller area – with tie lines whose transfer capability cannot be practically increased. The larger area, called area A, has self-sufficiency in generation capacity to meet its current and forecasted load. On the other hand, the smaller area, called area B, is deficient in generation capacity. Area B cannot meet its own load without the energy imports from area A, using the transfer capability of the existing tie lines. For our case, area B has a markedly higher load growth than area A. Hence, the problem of ensuring generation adequacy in area B becomes even more critical. The problem is to develop various expansion plans for area B to meet its forecasted load *effectively*. This requires the installation of additional generation resources in area B. For that reason, the objective of the study is to explore the applicability and cost-effectiveness of PV resources to build expansion alternatives to meet the future load of area B when transmission constraints between these two areas are very difficult or impossible to remove.

A. Literature Review

The problem at hand covers the intersection of the areas of economic analysis, probabilistic production costing for the two-area system and the application of DG and PV technology for resource expansion planning. Probabilistic production costing for the two-area system was done in a number of papers [1], [2] using bivariant cumulants and bivariant Gram-Charlier expansion. Production cost of each system for different tie line capacities was evaluated in [2].

The segmentation method [3] evaluated the two-area production costing with load correlation.

Cumulant method using available capacity distribution [4] considered the random characteristics of generating available capacity and the transmission capacity constraint. A methodology for computing production costs for multiarea systems that explicitly considered the transmission interconnection limitations, random unit forced outages and joint unit ownership has been proposed in [5].

Some of the work [6]-[9] evaluated the various benefits associated with applying distributed utility or DG in a distribution system alone or in transmission and distribution systems. The DG technologies considered in these studies were PV, fuel cells and battery storage systems. All of these studies did not consider the difficulty or impossibility of removing the tie line constraints being imposed on the system. As is clear from this brief survey, there is scant literature on the aspects of the problem in our present study.

III. METHODOLOGY

A. Economic Analysis Framework for A Two-Area System with Transmission-Constrained Network

The evaluation of resource expansion alternatives for a power system involves evaluating both the investment decision – long-term effects – and the variable aspects – short-term effects. In our study, the investment decision, the fixed costs, of the alternatives is not considered. Our emphasis is on the assessment of the variable costs of different alternatives for expanding the installed resource capacity of area B. The transmission constraint is explicitly considered. We do not consider the analysis of reliability aspects – a topic that has been thoroughly covered in the literature, e.g., the excellent treatment of two-area reliability interconnections in the textbook [10] and the multiarea reliability evaluation in [11].

Due to the focus on the variable economic aspects, the explicit consideration of uncertainty is important. Consequently, a probabilistic production costing framework is adopted for the study of expansion alternatives. A brief review on probabilistic production costing for a single area system is presented next.

The intent of production costing is to calculate a generation system's production cost, availability of energy for sales to other systems and fuel consumption [12]. Production costing models that recognize unit-forced outages and that compute the statistically expected energy production cost are called probabilistic production costing models. In probabilistic production costing, a forecasted load demand curve and a loading priority list of the units are assumed to be known. The load demand and the available generating capacity of each unit are considered to be random variables.

The probabilistic production costing model typically starts with a chronological load curve. Rearranging the hourly loads in a chronological load curve by starting with the highest load and next highest and so on, a load duration curve can be obtained. Clearly, the area under the load duration curve equals the area under the chronological load curve. This area represents the total energy required for the period. The physical interpretation is that, for a given load level l, the load is greater than or equal to l for h of the total hours considered. We use this observation to define the inverted load duration curve $\mathcal{L}(\bullet)$ and to associate a probability interpretation. For any value x, we define:

$$\mathcal{L}(x) = P\{L>x\} \tag{1}$$

For the period T, all aspects of the supply system are assumed to be uniform. To represent a supply unit A_n we use a simplified two-state model in which unit is either 100% available or 100% unavailable. For unit n with capacity c_n, let $p_n = P\{\text{unit } n \text{ is available for generation}\}$, then $q_n = P\{\text{unit } n \text{ is unavailable for generation}\} = (1 - p_n)$.

In general, units can be loaded as either single block or multiblocks [13]. We assume that each unit is loaded as a single block. When a unit is loaded, the load duration curve is converted into equivalent load duration curve by convolution. This is denoted by $\mathcal{L}_n$, which is the probability distribution of demand after loading the n^{th} unit. A general formula for obtaining equivalent load duration curve is expressed as:

$$\mathcal{L}_n(x) = p_n \ \mathcal{L}_{n-1}(x) + q_n \ \mathcal{L}_{n-1}(x-c_n) \tag{2}$$

The expected energy generated by the n^{th} unit in the system can be written as:

$$\mathcal{E}_n = T * p_n * \int_{c_{n-1}}^{c_n} \mathcal{L}_{n-1}(x)dx \tag{3}$$

Units are loaded according to a specified loading list. A new equivalent load duration curve is constructed upon the loading of each block of generation. After loading all supply units, the production costing simulation obtains the expected energy generated by each unit. From there, the total expected energy generated by all units in the system is determined by summing the individually generated energy, which can be written as:

$$\mathcal{E}_T = \sum_{i=1}^{n} \mathcal{E}_i \tag{4}$$

Total production cost of the system is defined as the total variable costs to meet the forecasted load demand in the system. If we consider only the variable fuel cost of the system, total production cost can be expressed as:

$$C_T = \sum_{i=1}^{n} (\mathcal{E}_i * \lambda_i) \tag{5}$$

We now apply the single area production costing model into our two-area system problem. The salient conditions of the problem are: load of area A is much greater than load of area B, installed capacity of area A is much greater than installed capacity of area B, and transfer capability of tie lines is fixed and less than load of area B. Under these conditions, we treat the tie capacity as a fixed deterministic quantity. The transfer capability is assumed to be utilized only for export from area A to area B. This constant tie flow is a fixed resource for area B. Consequently, we model the tie flow from area A as a constant supply equal in value to the transfer capability between areas A and B. Modeling of this fixed tie flow can be done by straightforward load modification. Since this is a "firm" supply, we subtract from the hourly load of area B the import from area A.

From the point of view of area A, we treat the export to area B as a constant additional load. Thus, we modify the chronological load of area A by adding an amount equal to the transfer capability to the hourly load of area A. After modeling the effect of the transfer capability in chronological load model of each area, we can separate the production costing problem of the two-area system into the two distinct problems of single-area probabilistic production costing. For each of the two separate problems, we can use the production costing methodology described above. All relationships above also apply to the problem of probabilistic production costing for two-area system with tie-line constraint. For the two-area system problem, we need only the information on the transfer capability and export or import at each hour to modify the corresponding load in each area.

Specifically, in our two-area system, the load of area A, taking into account the export to area B, becomes:

$$l'_A(t) = l_A(t) + e \tag{6}$$

where e is the transfer capability of tie lines. Similarly, for area B, the modified chronological load curve after accounting for import from area A can be written as:

$$l'_B(t) = l_B(t) - e \tag{7}$$

After modifying the corresponding chronological load curves in each area, the probabilistic production costing model for a single area is applied to the two-area system with the modified chronological loads to compute the expected production cost for each area. In this way, the probabilistic production costing problem for the two-area system with tie line constraint, explicitly represented, becomes the production costing of the two constituent single areas. Modeling of PV generation to be incorporated in production costing model is described next.

B. Modeling of PV Units

Due to the time dependent and non-dispatchable nature of PV units, schemes used for simulating conventional units are not applicable. The simulation of PV units requires a chronological representation of the generation pattern and the effective aggregation of the many individual units for modeling the ensemble. Basically, a PV plant consists of a collection of a large number of PV units at a given site. These units are ordered from the same manufacturing company and thus have statistically similar technical characteristics and performance. Practically, it is impossible to obtain a generation pattern of every unit of a PV plant. Statistically, however, it is possible to represent the overall generation from a set of units representing a collection of a larger number of these units as an ensemble. The random aspects of each PV unit are smoothed out through the averaging effect. It is first assumed that a typical daily generation pattern [14], shown in Fig. 1, is given.

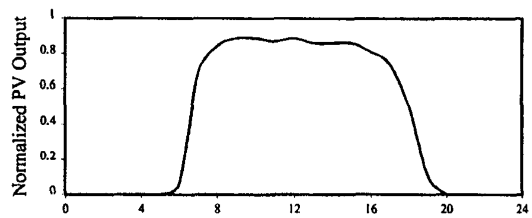

Fig. 1. Typical daily generation pattern of PV units

This daily generation pattern is assumed valid for each day of a month to construct a monthly generation pattern. This construction is based on the assumption that the weather is not changing significantly during the month. Such a generation pattern is constructed for each month of the year. A resultant generation pattern for a week is shown in Fig. 2, using the approach given.

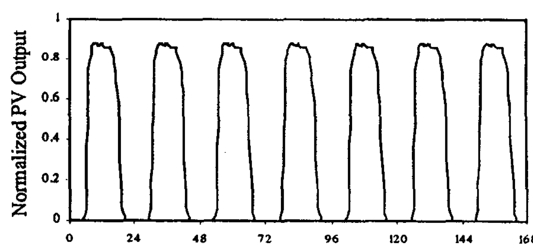

Fig. 2. Weekly generation pattern of PV units

The insolation availability data, shown in Fig. 3 and normalized to 1 for the month where maximum insolation is available, need to be incorporated in producing a yearly generation pattern. In PV generation, insolation availability refers to the 'density' of electrical power generation per squared meter of an area per day and given in units of kilowatt-hours per meter squared per day. These normalized insolation data are multiplied with a typical monthly PV generation pattern. In this way, a chronological generation pattern for an entire year can be obtained.

Another important factor in modeling PV units is the capacity reduction. Capacity reduction can be defined as the rate of reduction in capacity as generating unit ages during its useful life. Every type of generation technology exhibits some rate of capacity reduction during its useful technical life, and PV units are no exception to this phenomenon. PV units have a markedly higher reduction in yearly capacity

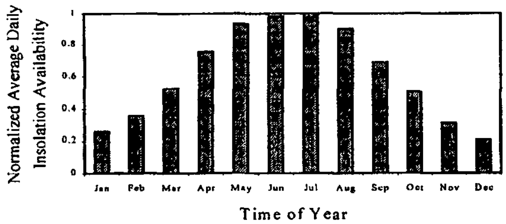

Fig. 3. Normalized average daily insolation availability

than conventional units. The reduced capacity affects the generation pattern by being scaled proportionately. The actual amount of PV capacity needed to be installed can be formulated as:

$$c_{pv}^{a} = c_{pv}^{r} (1 - \alpha)^{k} \tag{8}$$

where α is the rate of capacity reduction per year and k is the number of years after PV units are installed. Typical PV units are in size of a few kilowatts to some hundreds of kilowatts. In general, PV units are either grouped together in a single area or installed on building rooftops or residential compounds. The latter cases can also be considered as single load area. That justifies the fact that the capacities of all PV units can be lumped together as the capacity of a single PV plant.

In summary, data required for representing a yearly chronological generation pattern of PV units include: insolation data for a particular location, daily or monthly generation pattern, amount of capacity to be installed and rate of capacity reduction. After obtaining a yearly generation pattern of all PV units, the modified chronological load for smaller area B, after accounting for transferred energy from area A becomes:

$$l''_{B}(t) = l'_{B}(t) - l_{pv}(t) \tag{9}$$

Modified chronological load after accounting for import and PV output, $l''_{B}(t)$, is the type of load model that should be used with probabilistic production costing program which explicitly models the other types of dispatchable generating units.

IV. SIMULATION RESULTS

The two-area system, comprised of areas A and B, is represented for the purposes of evaluating the economics of expansion alternatives using PV generation for area B. The planning horizon for the study is 10 years. We selected this period as a reasonable duration over which the economic aspects of different alternatives can be compared. Also, the shorter 10 years period compared to the conventional 20-30 year horizon is more reflective of the trend under competitive conditions. The basic time period of the simulation is one week.

For area B, we ignore the effects of maintenance schedule of the units because incorporation of maintenance in production costing has considerably smaller impact on the area. For area B, the period of one year is broken down into four different seasons, each lasting 13 weeks. For each 13-week period, we simulate a 1-week period using the corresponding typical weekly load pattern. Then the result is multiplied by 13 to obtain the result for the entire season. Hence, we need four typical weekly load patterns for area B. The load model for area B is obtained from IEEE RTS system [15]. The modeling of PV units uses a weekly chronological generation pattern.

The expansion plans are built based on an annual load growth of 4% in area B. The reference expansion alternative is constructed using combined-cycle units. The rationale for using such units is based on the lower investment costs, higher efficiencies, and shorter lead times associated with these units compared to other existing generation technologies. In addition, because combined-cycle units use natural gas, they are environmentally quite clean.

The expansion plan is summarized in Table 1. In the table, reserve margins are computed by considering the imports from area A as firm available capacity. In year 0 (starting year), area B is capacity-deficient without the imports from area A. Combined-cycle units are added in alternate years so that in year 10, area B has installed capacity of 320 MW, whereas its forecasted peak load is 296 MW.

Table 1. Reference expansion plan with combined-cycle units

Year	Peak Load (MW)	Nameplate Capacity Addition (MW)	Total Effective Installed Capacity (MW)	Firm Capacity From Area A (MW)	Reserve Margin (%)
0	200	0	160	60	10.00
1	208	0	160	60	5.77
2	216	40	200	60	20.19
3	225	0	200	60	15.57
4	234	30	230	60	23.95
5	243	0	230	60	19.18
6	253	30	260	60	26.45
7	263	0	260	60	21.59
8	274	30	290	60	27.87
9	285	0	290	60	22.95
10	296	30	320	60	28.36

For alternative expansion plan, we apply three distinct DG technologies: PV, fuel cells, and microturbines. These technologies were selected due to the smaller area B's characteristics, which are compatible with the attributes, associated with these technologies, such as abundant solar availability and cheap natural gas. The capacities of DG units are in the range of a few kilowatts to a few megawatts. As such, they may be installed in small increments from less than 1 MW to a few megawatts capacity in every year. This modular nature of DG technologies is utilized by adding small increments in each year rather than the discrete increments due to the "lumpiness" of conventional combined-cycle units. The expansion plan is summarized in Table 2.

In year 1, we consider the combination of microturbines and PV resources: 8 MW of microturbines and 9 MW of PV are installed. The amount of PV installed explicitly takes into

Table 2. Alternative expansion plan with DG technology

Year	Peak Load (MW)	Nameplate Capacity Addition (MW)	Total Effective Installed Capacity (MW)	Firm Capacity from Area A (MW)	Reserve Margin (%)
0	200	0	160	60	10.00
1	208	17	176	60	13.47
2	216	16	191	60	16.03
3	225	17	206	60	18.24
4	234	17	221	60	20.10
5	243	16	235	60	21.23
6	253	17	248	60	21.71
7	263	17	262	60	22.35
8	274	16	275	60	22.39
9	285	17	288	60	22.25
10	296	17	300	60	21.60

account the capacity reduction that occurs. For example, the effective capacity of 9 MW PV installed in year 1 reduces to approximately 8 MW in year 2. Such a reduction in capacity is represented for each subsequent year. The results are given in the total effective installed capacity column of Table 2. The capacity reduction is assumed to be 11% per year.

In year 2, the combination of microturbines and fuel cells of 8 MW each is installed. The other combination of fuel cells (8 MW) and PV (9 MW) is installed in year 3. This same pattern of installation is repeated in the remaining planning years. Again, reserve margins are computed by considering the imports from area *A* as firm capacity.

Area *A* exports energy, equivalent to available transfer capability, to area *B* in each hour during the entire planning period. The production costs for all case studies are computed on annual basis. We will then describe the discussion of case studies made.

Case 1: Reference Expansion Case

Fig. 4 shows the area *B* production costs result for the reference expansion case using conventional technology. The production costs for area *B* include the costs of supply associated with the import of energy from area *A*. However, it is considered constant for all the cases studied. This component of the production costs is ignored in all cases for the sake of simplicity.

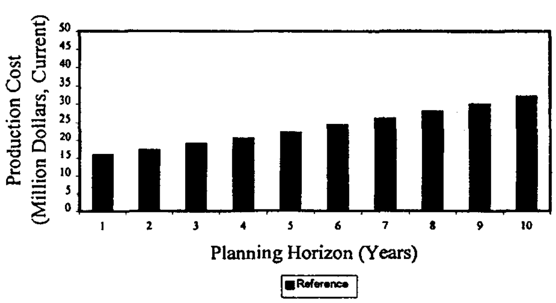

Fig. 4. Area *B* production costs: reference expansion case

Case 2: Alternative Expansion Case

The production costs of the alternative expansion case using DG technology are shown in Fig. 5. Except for years 2, 4, and 5, the production costs of DG alternative are less than the reference case with conventional technology. The reason why the production costs of DG alternative are much higher than conventional one in year 2 is that PV units are not included in that year's expansion plan. Hence, the load is served by the remaining two DG resources, which use natural gas fuel, causing the higher production costs. When PV units are installed in the later years, the DG alternative has less production costs when compared with that using the conventional generation technology.

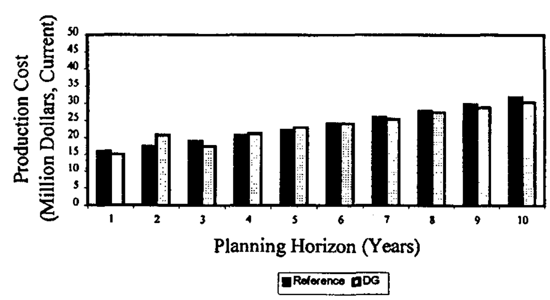

Fig. 5. Area *B* production costs: alternative expansion case

Case 3: Alternative Expansion Case with Different PV Penetrations

The results of the sensitivity case studies on PV penetration are shown in Fig. 6. The alternative expansion case with different PV penetrations are simulated and compared to the reference case. It is found that the alternative expansion case with 20% PV penetration is more expensive than that reference case in every year of the planning horizon. On the other hand, except in the first two years, the case with 80% PV penetration shows economic attractiveness for the DG-based expansion alternative during all the other years of planning horizon. This is because, the amount of PV installed in the first two years is small, compared to the amount installed in the later years. Consequently, as the amount of PV installation increases, the production costs decrease.

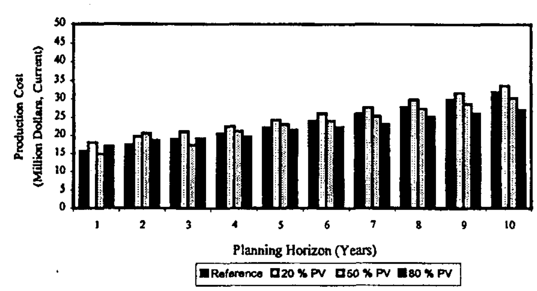

Fig. 6. Area *B* production costs: PV penetration case (reference insolation availability)

Case 4: Alternative Expansion Case with both Different PV Penetrations and Increased Insolation Availability

The insolation availability is increased by 50% for all three PV penetration cases. The results of the study are shown in Fig. 7. It is clearly found that, in all years for alternative expansion case, the plan with 20% PV penetration is still more expensive than conventional technology-based alternative. But, the plan with 80% PV penetration is not only less expensive than conventional technology-based alternative, but also the least expensive compared with other plans. As PV penetration increases, the additional insolation availability clearly results in increased economic attractiveness for alternative expansion plan.

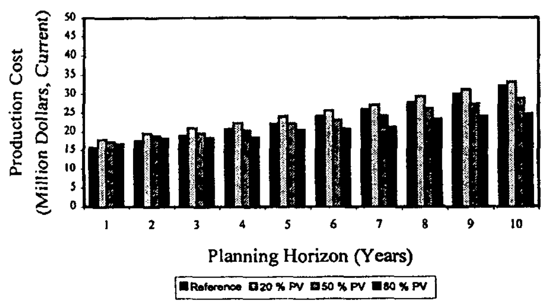

Fig 7. Area *B* production costs: PV penetration case (increased insolation availability)

V. CONCLUSIONS

A study was made to explore the applicability and cost-effectiveness of PV generation in a two-area system interconnected by tie lines whose transfer capability is severely limited. Single area production costing model has been effectively extended to a two-area system production costing problem where the real power transfer between the areas is explicitly accounted. A fresh attempt was made to model the generation from PV units to be included in resource planning methods. Time dependent nature of these units is emphasized. It is found that the transfer capability of tie lines plays an important role in our study of economic analysis. Higher insolation availability and higher PV penetration are important factors in cost-effectiveness of PV resources in a transmission-constrained load area of an interconnected system.

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VII. BIOGRAPHIES

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George Gross (F' 1988) is the Professor of Electrical and Computer Engineering and Institute of Government and Public Affairs at the University of Illinois at Urbana-Champaign. His current research and teaching activities are in the areas of power system analysis, planning, economics, and operations, utility regulatory policy, and industry restructuring. His undergraduate work was completed at McGill University, and he earned his graduate degrees from the University of California at Berkeley. He was previously employed with Pacific Gas and Electric Company.