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Integrated and Simultaneous Model of Power Expansion Planning with Distributed Generation

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Abstract – *This study proposes a model based on mixed-integer linear programming (MILP) for the integrated expansion planning of generation and transmission systems with the implementation of distributed generation (DG). Most DG planning takes place after generation and transmission planning has been conducted. This model can be used to include DG potential simultaneously with generation and transmission expansion. DG is modelled as a negative load therefore DG is treated as a non-dispatchable unit of power generation. The objective of the model is to minimize overall cost including the investment cost of the generation units, DG units, and transmission lines, and the operating cost of the generation and DG units. The proposed model is static-deterministic model in the form of MILP. The model was evaluated using the 6-bus Garver's test. To prove the effectiveness of the model, it was evaluated using the IEEE 46 Bus Test. The results show that due to the impact of DG on power system expansion planning ,the overall cost was reduced. The simulation results also show that a different optimal network configuration can be achieved by DG implementation in expansion planning.*

Keywords: *Integrated Expansion Planning, Generation Expansion, Transmission Expansion, Distributed Generation, Mixed Integer Linear Programming*

Nomenclature

Indices

i, j	Bus
ng	Number of generators over plants on each bus
nc	Number of circuit over two buses
gt	Generator technology
q	Generator option capacity for each generator technology
o	Demand block

Sets

Ω_o	Existing transmission lines
Ω	Prospective transmission lines

Parameters

B_{ij}	Transmission line susceptance connected bus *i,j* [S]
$U_{i,j}^{EL}$	Circuit number of existing transmission line
FL_{ij}^{Max}	Maximum flow capacity of transmission line connected bus *i,j* [MW]
IL_{ij}	Investment line of transmission line connected bus *i,j* [$]
$EPG_{i,gt}^{Max}$	Maximum capacity of existing generation unit installed in bus *i* [MW]
$NPG_{gt,q}^{Opt}$	Capacity option of new generating units each generator technology *gt* for option *q* [MW]
$NGC_{gt,q}^{Opt}$	Cost of new generating units each generator technology *gt* for option *q* [$]
$FixOM_{gt}$	Fixed O&M cost for each generator technology *gt* [$]
$VarOM_{gt}$	Variable O&M cost for each generator technology *gt* [$]
$GFOR_{gt}$	Forced outage rate for each generator technology *gt* [%]
$GPOR_{gt}$	Planned outage rate for each generator technology *gt* [%]
$MaxOH_{gt}$	Maximum operating hours of generator technology *gt*
$CO2_{gt}$	CO_2 emission factor for each generator technology *gt* [Ton/kWh]
NOx_{gt}	NO_x emission factor for each generator technology *gt* [Ton/kWh]
$SO2_{gt}$	SO_2 emission factor for each generator technology gt [Ton/kWh]
$CO2Cost_{gt}$	Cost of CO_2 emission factor for each generator technology *gt* [$/Ton]
$NOxCost_{gt}$	Cost of NO_x emission factor for each generator technology *gt* [$/Ton]
$SO2Cost_{gt}$	Cost of SO_2 emission factor for each generator technology *gt* [$/Ton]
$PDHour_o$	Demand level duration for demand block *o* [hours]
$PD_{d,o}^{Max}$	Maximum demand level in each demand

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	bus *d* for demand block *o* [MW]
MRM	Maximum reserve margin [%]
Variables	
$PG_{i,o}^{E}$	Electricity production of installed generation units [MWh]
$Bin_{i,gt,ng,q}^{G}$	Binary decision variable of new generating units {0,1}
$NPG_{i,gt,ng}^{Max}$	Maximum capacity of new generating units [MW]
$PG_{i,gt,o}^{N}$	Electricity production of new generating units [MWh]
$Bin_{i,dgt,ndg,dgq}^{DG}$	Binary decision variable of new DG units {0,1}
$W_{i,gt,ng}^{G}$	Electricity production by each generating unit [MWh]
$W_{i,gt,ng}^{DG}$	Electricity production by each DG unit [MWh]
$NDG_{i,gt,ng}^{Max}$	Maximum capacity of new DG units [MW]
$NPDG_{i,gt,o}$	Electricity production of new DG units [MWh]
$PL_{ij,o}$	Line power flow [MW]
$Bin_{ij,nc}^{L}$	Binary decision variable of new transmission line {0,1}
$\theta_{i,o}$	Bus angle [rad]

I. Introduction

Electricity demand continues to increase relative to the growth in the population and economic activity. Ensuring a reliable supply of electricity to meet demand is the main task of generation companies (GENCOs). In general, generation expansion planning (GEP) aims to determine the optimal capacity of power plants in order to satisfy the system load. GEP is undertaken prior to transmission expansion planning (TEP). GEP and TEP also can be undertaken simultaneously.

The coordination of GEP and EP is based on a heuristic market-based simulation model in [1]. This study proposes decision of the investment based on desirable location generated by individual decisions of stakeholder of autonomous market. This model was constrained by limited information shared by the market players. The proposed model in this study results expansion mechanism on generation and transmission capacity based on market that enable competition to follow market need. The simultaneous planning for generation and transmission capacity based on reliability was done in [2] based on the DC model of load flow. This DC load flow was used to indicate the constraint of the transmission flow that eliminates the disconnected bus problem. A reliability assessment was undertaken at the hierarchical level (HL) II. The result of this model showed economic level of reliability for a given system with minimum investment cost. The coordination of GEP and TEP was also undertaken with fuel transport being a constraint in the model proposed in [3]. In addition to reducing the capital cost of the new generation unit and adding a new transmission line, another constraint is the fuel cost, including the cost of transporting the fuel to the generating unit locations. Fuel availability was also treated as a constraint in this model. The co-optimization of the GEP and TEP model based on a micro-grid was proposed in [4]. As well as the capital cost of the addition of a new generation unit and transmission line, this model also included the investment and operating cost of the local micro-grid and the cost of expected unserved energy. The reliability of the system was taken into consideration by including the cost of unserved energy which reflects the cost of load shedding. This model of co-optimization was divided into an expansion problem and a yearly reliability sub-problem. The optimal solution was resulted by the examination planning problems with addition of system reliability as an objective of sub-problem. A static model of simultaneous GEP and TEP was proposed with three-level mixed integer linear programming (MILP) with a case study on the power system in Chile in [5]. In the model, the lowest level represented market-based equilibrium, the intermediate level represented equilibrium in generation capacity expansion, and the upper level represented transmission line expansion based on the expansion of generation capacity. A probabilistic approach to the integration of GEP and TEP was proposed in [6]. This model also considered the criteria of power system reliability. Reliability criteria was represented by the random outage of a generator and transmission line known as the chronological forced-outage rate (FOR). The cost consideration of the model included capital and operation cost along with the cost of expected energy not supplied (EENS). A dynamic model of coordination of GEP and TEP was proposed in the form of mixed integer nonlinear programming (MINLP) [7]. Bender's decomposition method was used to transform MINLP into MILP as a main problem and linear programming (LP) as a sub-main problem. The model also investigated the system reliability at HL II. Another form of dynamic model is the multi-period integrated framework that was developed in [8] for GEP and TEP and natural gas grid expansion planning. The objectives of this model were to minimize the total capital cost and operation cost of electrical power generation as well as the natural gas grid. The result of the model were generation requirement with location and capacity, transmission line requirement with type and lines termination, and natural gas grid requirement to provide newly built power plant and natural gas need. A coordinated generation and transmission expansion planning model based on the probabilistic approach was proposed in [9] as a multi-objective model using non-boundary intersection. This model instantaneously minimizes the overall cost of planning and fuel, externality cost in term of SO_2 and NOx emission and fuel price changes while the reliability of the power system is maximized. A Pareto-optimal solution was achieved by incorporating the non-boundary intersection method.

Distributed generation (DG) is seemly a more attractive option in the planning and operation of power systems. Even so, a model which implements DG focuses on the distribution network. The impact of DG implementation on a distribution network can be viewed from several perspectives , such as improving reliability [10], [11], reducing distribution network losses [12]-[14], incentive cost impact [15], and improving voltage stability [16], [17]. In relation to transmission expansion planning, several models which implement DG have been proposed. The impact of DG implementation on the TEP model in reducing cost can be seen in [18]. The results of this model show that DG may reduce the capital cost in transmission expansion planning. However, the impact of DG implementation is significantly affected by many aspects, such as DG location, network topology, and technical constraints in the power system. A TEP model with DG implementation was also proposed with a multi-objective optimization model in [19]. This model comprised several uncertain variables which resulted in flexible decision-making in relation to in transmission capacity expansion. The uncertain variables in this model were generation expansion, system load, and other markets variable. A combined model of GEP and TEP with intermittent renewable energy sources was also proposed in [20]. Coordination model of GEP and TEP with the implementation of DG was proposed in [21]. This model treated the optimization model of DG as separated model from the main model of GEP and TEP. The first step was determination of optimal generation planning. The optimal of DG capacity was earned by separated optimization model. In combined model of GEP and TEP, DG capacity was used to adjust network demand. There is also no binary decision variable in this model.

The main contributions of this paper are:

1. a model is proposed which includes the simultaneous determination of generation capacity and transmission line adequacy, and
2. distributed generation is added in the proposed model as an integrated objective and constraint function which is different from the model previously proposed in [21]. In this model, GEP and TEP are undertaken in the one process of optimization.

II. Problem Statement

The optimal design and planning of an interconnected power system deals with the optimization of power generation and transmission capacity expansion to meet the given electrical load. Expansion planning can be divided into generation expansion planning (GEP) and transmission expansion planning (TEP). Expansion planning involves a single bus or a multi-bus approach. The single bus approach assumes the transmission network is never overloaded for a projected demand whereas the multi-bus approach is limited by the capacity of the transmission network. Usually, GEP is undertaken prior to TEP, hence the outcomes of GEP will be used as input for TEP. The goal of TEP is to minimize network expansion considering GEP and projected demand.

The model proposed in this paper is developed based on the integration of GEP and TEP. Using this model, generation and transmission capacity expansion planning can be done simultaneously. This model is well suited for power systems that cover a very large area [22]. On the other hand, DG plays an important role in modern power systems. Consideration should also be given to DG in the expansion planning of power systems. Therefore, the proposed model will also include DG as a component in expansion planning. The impact of DG implementation will be analyzed in terms of the reduction in the overall system cost and deferral of network configuration.

III. Problem Formulation

The integrated model of GEP and TEP is written as a G-TEP model in the form of a mathematical programming problem. This problem comprises binary variables that denote whether the transmission lines are built or not and other binary variables for generating and DG units. The model will be developed as mixed integer nonlinear programming (MINLP) model where the product of binary variables and continuous variables appear in TEP formulation. To reduce the computation time, the developed MINLP model will be converted to a MILP model by the linearization of the nonlinear constraint.

III.1. Load Duration Curve

The operational condition of a power system is represented by the load duration curve (LDC). LDC describes the load level change over time which is used to determine the level of generating unit production. In the view of expansion planning, LDC consists of load level information for each hour in a year.

From the view of expansion planning, linear approximation is used to produce practical LDC. Linear LDC is shown in Fig. 1.

III.2. Objective Function

The objective function of the G-TEP problem is to minimize the overall expansion cost. Considering the static-deterministic model, the objective function of the G-TEP problem is expressed as shown in equation (1). The objective function in (1) consists of four part which are investment cost of newly built generating units NG^{inv}, operation cost of installed and newly built generating units G^{OM}, investment cost of an added transmission line NL^{inv}, and externality cost of electricity production by the installed and new generating units G^{EC}. Each part of the objective function is defined in equations (2) to (5) respectively:

$$\min(NG^{inv} + G^{OM} + NL^{inv} + G^{EC}) \tag{1}$$

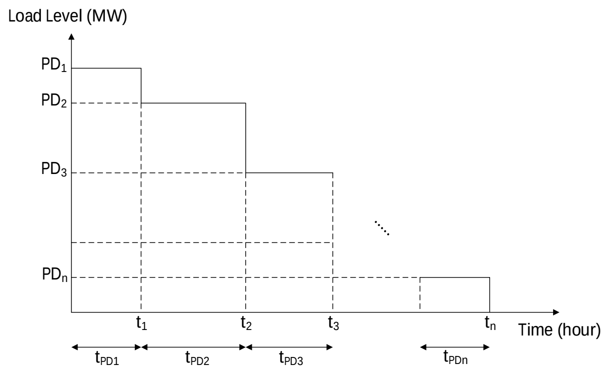

Fig. 1. Linear LDC of electrical power system

$$NG^{inv} = \sum_{i}\sum_{gt}\sum_{ng}\sum_{q=1}^{q} NGC_{gt,q}^{Opt} Bin_{i,gt,ng,q}^{G} \quad (2)$$

$$G^{OM} = \sum_{o} PDHour_o \sum_{i}\sum_{gt} VarOM_{gt}(PG_{i,o}^{E} + PG_{i,gt,o}^{N}) \quad (3)$$

$$NL^{inv} = \sum_{i}\sum_{j}\sum_{nc} IL_{ij} Bin_{i,j,nc}^{L} \quad (4)$$

$$G^{EC} = \sum_{o} PDHour_o \sum_{i}\sum_{nc} \big(CO2_{gt}CO2Cost_{gt} + NOX_{gt}NOXCost_{gt} + SO2_{gt}SO2Cost_{gt}\big)\big(PG_{i,o}^{E} + PG_{i,o}^{N}\big) \quad (5)$$

III.3. DC Load Flow

Power flow in the G-TEP model is used as a constraint. The power flow equation is used to determine the power balance in every node or bus before and following expansion planning. In this model, the DC power flow will be implemented. The state of each bus before expansion, power flow n is calculated by equation (6). P_G^0 and P_D^0 are the active power of generating unit and peak load of demand. B^0 and θ^0 are the line susceptance matrix and voltage angle vector at peak load before expansion. The variable after expansion can be stated as P_G^t, P_D^t, vector θ^t, and matrix B^t. The power balance in each bus after expansion is calculated using equation (7). The difference between each variable before and after expansion is stated in equations (8)-(11). ΔP_G represents the added generation unit. Demand growth is represented by ΔP_D. The additional line which is needed in after expansion is represented by ΔB. The voltage angle deviation before and after expansion is represented by $\Delta\theta$:

$$P_G^0 - P_D^0 = B^0 \cdot \theta^0 \quad (6)$$

$$P_G^t - P_D^t = B^t \cdot \theta^t \quad (7)$$

$$P_G^t - P_G^0 = \Delta P_G \quad (8)$$

$$P_D^t - P_D^0 = \Delta P_D \quad (9)$$

$$B^t - B^0 = \Delta \mathrm{B} \quad (10)$$

$$\theta^t - \theta^0 = \Delta\theta \quad (11)$$

III.4. Constraints

There are two kinds of constraints, investment and operating. Investment constraints are used to determine the type of technology which is needed and the capacity of the generating units and transmission lines. The investment constraints of the model are stated in equation (12) to (15).

The constraints in (12) determine the additional generating capacity to meet the demand in the system. These constraints are used to represent the capacity of the generating unit as a discrete decision variable because generating units are typically built in blocks of preset size. The size and type of the generating units that will be added are determined by $Bin_{i,gt,ng,q}^{G}$. Each option for a generating unit is only selected once in generating unit technology and the number in each bus. This condition will be achieved by the implementation of constraint (13). Constraint (14) is used to define $Bin_{i,gt,ng,q}^{G}$ as a binary variable. In the same way, the number of transmission lines that will be added is determined by binary variable $Bin_{i,j,nc}^{L}$ as stated in constraint (15). This binary variable will directly involve the total cost of line investment of the objection function:

$$NPG_{i,gt,ng}^{\max} = \sum_{q} Bin_{i,gt,ng,q}^{G} NPG_{i,gt,q}^{Opt} \quad (12)$$

$$\sum_{q} Bin_{i,gt,ng,q}^{G} \le 1 \quad (13)$$

$$Bin_{i,gt,ng,q}^{G} \in \{0,1\} \quad (14)$$

$$Bin_{i,j,nc}^{L} \in \{0,1\} \quad (15)$$

Operating constraints consist of power flow, power flow limits through existing and new lines and the limit of power generated by each generating unit. Operating constraints are implemented for all load operating conditions. Constraints related to power flow through existing and candidate line are stated in (16). Power flow through corresponding transmission lines is limited by constraints (17). Power quantity will be produced by existing and new generating units which are bounded by constraint (18) and (19) respectively:

$$PL_{i,j} = \big(U_{i,j}^{EL} + U_{i,j,nc}^{NL}\big) B_{i,j}\big(\theta_i - \theta_j\big) \quad (16)$$

$$\big|PL_{i,j}\big| \le \big(U_{i,j}^{EL} + U_{i,j,nc}^{NL}\big) PL_{i,j}^{\max} \quad (17)$$

$$0 \le PG_{i,gt}^{E} \le EG_{i,gt}^{\max} \quad (18)$$

$$0 \leq PG_{i,gt}^{N} \leq \sum_{ng} NPG_{i,gt,ng}^{\max} \tag{19}$$

Electricity produced by each generating unit is defined by the constraint in equation (20). The total electricity production of all generating units (existing and newly built) should meet demand load at peak operation point. Therefore, the sum of electricity production of all generating units must be greater or equal to the total electricity demand (TED) in the system. This is stated in constraint (21). On the other hand, the total capacity of the generating unit must meet the determined reserve margin. This situation can be achieved by implementing constraint (22) in the model:

$$W_{i,gt,ng}^{G} \leq CF_{gt} MaxOH_{gt} \left(EPG_{i,gt}^{Max} + NPG_{i,gt,ng}^{Max} \right) \tag{20}$$

$$\sum_{i} \sum_{gt} \sum_{ng} W_{i,gt,ng}^{G} \geq TED \tag{21}$$

$$\sum_{i} \sum_{gt} EPG_{i,gt}^{Max} + \sum_{i} \sum_{gt} \sum_{ng} NPG_{i,gt,ng}^{Max} \leq (1 + MRM) \sum_{d,o|o=peak} PD_{d,o}^{Max} \tag{22}$$

III.5. DG Implementation

In this proposed model, DG will be implemented as a negative load. In this manner, DG will reduce power demand in all buses with load. DG implementation will change the objective function of the model and several constraints will also be added. The objective function in equation (1) should be modified by adding DG investment as a new part of this equation. Therefore, the objective function will be as seen in equation (23) where $DG_{i,dgt,ndg}^{inv}$ is the investment cost of DG. The definition of $DG_{i,dgt,ndg}^{inv}$ is stated in equation (24). The operating cost of DG should also be included in the objective function of the model. The operating cost of DG units is $DG_{i,dgt,ndg}^{opt}$ and is stated equation (25):

$$\min \left(NG^{inv} + G^{OM} + NL^{inv} + G^{EC} + DG^{inv} + DG^{OM} \right) \tag{23}$$

$$DG^{inv} = \sum_{i} \sum_{dgt} \sum_{ndg} \sum_{dgq} NDGC_{dgt,qdg}^{Opt} Bin_{i,dgt,ndg,qdg}^{DG} \tag{24}$$

$$DG^{OM} = \sum_{o} PDHour_{o} \sum_{i} \sum_{dgt} PDG_{i,dgt} VarOMDG_{dgt} \tag{25}$$

The power balance constraint in equation (7) should be modified to accommodate DG installation in the possible bus that will adjust network demand.

This constraint is seen in equation (26). This constraint will treat DG as negative load in all buses with load to reduce local load if it is feasible to install a DG. Similar to the generation unit, DG capacity is predetermined as blocks therefore constraints to select which DG capacity will be installed should be added in the model.

The production of DG should be limited to the chosen DG capacity. To determine a feasible capacity for the DG units, $PDG_{i,dgt}^{\max}$, is defined in equation (27). DG will have an effect on electricity production in the system. Therefore, electricity generated by DG should be considered in constraint (21):

$$P_{G}^{t} - \left(P_{D}^{t} - P_{DG}^{t} \right) = B^{t} \cdot \theta^{t} \tag{26}$$

$$PDG_{i,dgt}^{\max} = \sum_{qdg} Bin_{i,dgt,ndg,qdg}^{DG} PDG_{i,dgt,qdg}^{Opt} \tag{27}$$

III.6. Complete Model

The complete G-TEP model with DG implementation that was described in the previous section can be summarized as follows:

Objective function

{Equation (20)}

subjected to:

{Equations (2) – (4)}
{Equations (12) – (19)}
{Equations (21) – (24)}

This model is a MINLP where there is a product of a continuous variable and a binary variable in constraint (16).

To reduce computation burden, MINLP can be converted to MILP by a linearizing constraint (16). This is done using equation (16) for the installed and prospective line. The result of linearization is stated in equations (28) – (31).

For installed lines:

$$PL_{i,j} = U_{i,j}^{EL} B_{i,j} \left(\theta_{i} - \theta_{j} \right) \tag{28}$$

$$\left| PL_{i,j} \right| \leq U_{i,j}^{EL} PL_{i,j}^{\max} \tag{29}$$

For prospective lines:

$$\left| PL_{i,j} - B_{i,j} \left(\theta_{i} - \theta_{j} \right) \right| \leq M \left(1 - Bin_{i,j,nc}^{NL} \right) \tag{30}$$

$$\left| PL_{i,j} \right| \leq Bin_{i,j,nc}^{NL} PL_{i,j}^{\max} \tag{31}$$

Based on the results of linearization, the G-TEP model in the form of MILP can be summarized as follows:

Objective function

{Equation (20)}

subjected to:

{Equations (2) – (4)}
{Equations (12) – (15)}
{Equations (17) – (19)}
{Equations (21) – (23)}
{Equations (25) – (28)}

The flowchart that describes the operation of the model is shown in Fig. 2.

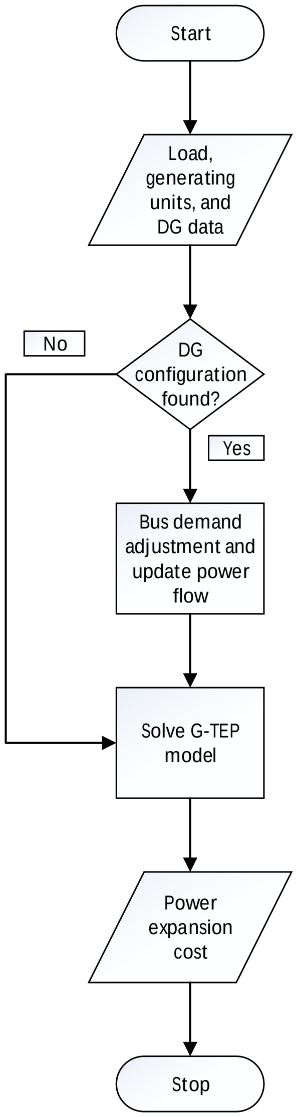

Fig. 2. The flowchart of the model with DG implementation

Input data is consisted of expected load, generating unit, and DG unit. Model will detect weather DG is feasible to be included in the system or not. When DG configuration was found, model will adjust the load data in each bus since DG was model as negative load. Based on adjusted load with the presence of DG, power flow equation will be updated to determine power balance in each bus. Next step, the model of GTEP will be solved to result the optimal overall cost of power expansion planning. The minimum cost will be the result to indicate the optimal configuration of the network based on expected load.

This model is solved by the CPLEX solver for MILP and is implemented under the Advanced Interactive Multidimensional Modelling Systems (AIMMS). The optimality relative tolerance was set to 0.001.

IV. Cases Study

IV.1. Garver's 6 Bus System

In this section, the simulation results are provided to demonstrate the application of the proposed model. The case study used is Garver's 6 Bus system which was originally published in [23]. The modified Garver's test system in Fig. 3 shows the existing power system which is to be expanded in the future to meet the growth in electricity demand. A new bus 6 will be added to the system to meet the total demand. This new bus is not currently connected in the existing system. The proposed model will calculate the minimum number of generating units to be added in the network expansion.

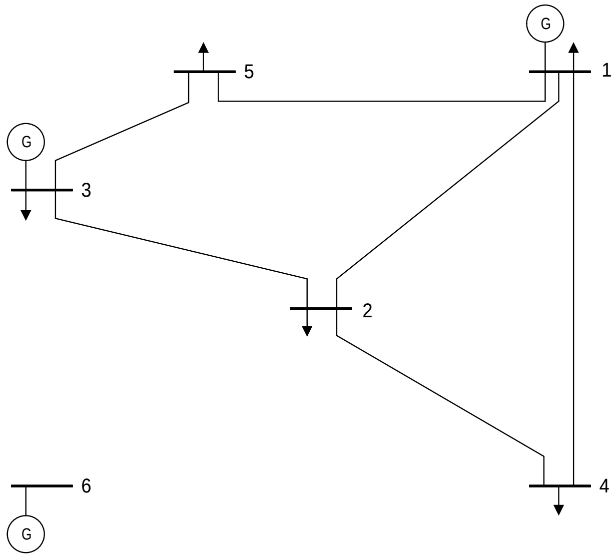

Fig. 3. Garver's 6 bus system

The current generation and demand data is presented in Table I. As the model incorporates a DC load model, power losses are not considered in this analysis. Line data for the existing system are shown in Table II. Each line is limited to their capacity as shown in the fourth column of Table II. To meet projected demand, there are four possible line additions to the system.

IV.2. IEEE 46 Bus Test System

IEEE 46 bus system was published in [24] which compares and tests the reliability analysis of power systems.

TABLE I
GENERATION AND LOAD DATA OF EXISTING SYSTEM

Bus	Cap^{max} (MW)	$Op.Cost$ ($/MWh)	P_d^D (MW)
1	50	18	100
2	-	-	300
3	165	25	75
4	-	-	200
5	-	-	275

TABLE II
LINE DATA OF EXISTING SYSTEM

From Bus	To Bus	x_l (pu)	F_l^{Max} (MW)
1	2	0.4	100
1	4	0.6	80
1	5	0.2	100
2	3	0.2	100
2	4	0.4	100
3	5	0.2	100

A modified version of this test is suitable for test generation and transmission expansion planning. This test system includes data that is required by the generation and transmission expansion model. Line data includes line impedance, bus to bus line connection, line capacity, line length, and line reliability. The expected annual peak load of the system is 6,880 MW. This peak load capacity represents the load in 4 years to come. The total current generating unit capacity is 5,273 MW which consists of 12 generators. Details on the system configuration, generating unit data, line data, and load data in each bus can be found in the appendix. This test system was modified to suit the developed model. The modified data are the new transmission line cost and capacity. These modifications were made to show the effect of DG implementation on the expansion of an electrical power system.

V. Results and Discussion

V.1. Simulation Data

For simulation purposes, several assumptions should be included to complete the data on the test system. In the simulation, LDC consists of only 2 load levels, which are base and peak load. Base load is determined as half of peak load. The time duration of base and peak load levels is 6,000 and 2,760 hours respectively.

To meet expected electricity demand, additional generating units should be added to the system. The prospective generating units are shown in Table III. The types of prospective generating units are Ultra Supercritical Coal (USC), Gas Turbine (GT), Natural Gas Combined Cycle (NGCC), Hydropower, and Nuclear. This table consists of capital cost and cost of fixed and variable operating and maintenance costs. The performance data on the generating units include Force Outage Rate (FOR) and Planned Outage Rate (POR). FOR and POR will determine the maximum availability of each type of generating unit technology.

This table also shows the environmental impact of electricity generation for each technology. Table IV provides the cost and performance data for DG technology which consist of photovoltaic (PV), wind turbine (WT), and biomass. There is no environmental impact by DG technology in generating electricity. Table III and Table IV were published in [25]. The externality cost regarding each type of emission can be found in [26]. These data will be used in G-TEP simulation for Garver's 6 bus system and IEEE 46 bus test system.

V.2. Simulation Result of Garver's 6 Bus System

For Garver's 6 bus system, the G-TEP simulation has an additional assumption regarding the availability of renewable sources. Hydropower can only be built in bus 3 and with a maximum capacity of 100 MW. Photovoltaic can only be built in bus 1 and 3 while a wind turbine can only be built in bus 2 and 4. Biomass DG has a maximum capacity of 50 MW and can only be built in bus 5.

The prospective line in the G-TEP simulation for Garver's 6 bus system is shown in Table V. Each line is limited to its capacity, as shown in the fourth column of the table. To meet projected demand, the G-TEP model should have the ability to determine whether additional lines are needed not only for the new circuit but also for line reinforcement in the form of a parallel circuit.

TABLE III
COST AND PERFORMANCE OF PROSPECTIVE GENERATING UNITS

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Var. O&M ($/MWh)	SO_2 (lb/MMBtu)	NO_X (lb/MMBtu)	CO2 (lb/MMBtu)	FOR (%)	POR (%)
USC	3,636	42.1	4.6	0.1	0.06	206	6	10
GT	1,104	17.5	3.5	0.001	0.03	117	3	5
NGCC	978	11	3.5	0.001	0.0075	117	4	6
Hydro	3,487	15	6	-	-	-	5	1.9
Nuclear	5,945	100.28	2.3	-	-	-	4	6

TABLE IV
COST AND PERFORMANCE DATA FOR DG TECHNOLOGY

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Var. O&M ($/MWh)	FOR (%)	POR (%)
WT	1,877	39.7	-	2	-
PV	2,671	23.4	-	0.6	5
Biomass	990	20	-	7	9

TABLE V
PROSPECTIVE LINE CHARACTERISTICS

From Bus	To Bus	x_l (pu)	F_l^{Max} (MW)	Line Cost (10^6×$)
1	2	0.4	100	40
1	3	0.6	80	60
1	4	0.2	100	20
1	5	0.2	100	20
1	6	0.4	100	40
2	3	0.2	100	20
2	4	0.3	100	38
2	5	0.68	70	68
2	6	0.31	100	31
3	4	0.3	100	30
3	5	0.59	82	59
3	6	0.48	100	48
4	5	0.63	75	63
4	6	0.3	100	30
5	6	0.61	78	61

The simulation results for Garver's 6 bus system are shown in Table VI and Table VII. The optimal expansion of the power system without DG implementation is shown in Table VI. Table VI-A shows that a generation unit must be added with a total capacity of 220 MW.A new generation unit must be installed at bus 1 and bus 5 with a capacity of 180 MW of NGCC and 40 MW of CT respectively. The new CT will only be operated to provide electricity at peak load condition, whereas the new NGCC will operate at all load condition with operating capacity of 175 MW and 180 MW for base and peak load, respectively.

An additional line must be installed to meet the expected electricity demand. For optimal expansion, two new lines connecting bus 2 – 6 and bus 4 – 6 need to be added. Each new line has 2 parallel circuits with reactance and capacity as shown in Table VI-B. By adding these two new lines, bus 6 will now be connected to the system. In relation to expansion cost, the total cost for optimal configuration without DG implementation is 196.21×10^6 USD. The total cost of power system expansion consists of the O&M cost of the generating unit, the new generating unit investment cost, externality cost of the generating unit, and new line investment cost. Details of these costs are shown in Table VI-C.

TABLE VI
OPTIMAL EXPANSION FOR GARVER'S SYSTEM WITHOUT DG IMPLEMENTATION

A. **Generator Addition**

Bus No.	Technology	Capacity (MW)	Operating Point Base	Operating Point Peak
1	NGCC	180	175	180
5	GT	40	0	40

B. **Transmission Line Addition**

From-to Bus	Reactance (p.u.)	Capacity (MW)
2-6	2 × j0.3	2 × 100
4-6	2 × j0.3	2 × 100

C. **Expansion Cost**

Cost Type	Cost ($\times10^6$ USD)
Total Generator O&M Cost	62
Total Generator Investment Cost	2.21
Total Line Investment Cost	120
Total Externality Cost	12
Total Cost	196.21

Table VII shows the optimal system configuration after the expansion of the power system with DG implementation. In contrast to the previous results, three additional generating units must be installed, these being 135 MW of NGCC at bus 1, 40 MW of GT at bus 2, and 50 MW of GT at bus 5. A new NGCC is used for both base and peak load level with an operating point of 120 MW and 135 MW, respectively. A new GT at bus 2 and bus 5 will only operate at peak load level. In addition, three types of DG technology must be installed, which are 4×10 MW of WT in bus 2 and bus 4 and 4×10 MW of biomass in bus 5.

TABLE VII
OPTIMAL EXPANSION FOR GARVER'S SYSTEM WITH DG IMPLEMENTATION

A. **Generator Addition**

Bus No.	Generator Technology	Capacity (MW)	Operating Point Base	Operating Point Peak
1	NGCC	135	120	135
2	GT	40	0	40
5	GT	50	0	50

B. **DG Addition**

From-to	Reactance (p.u.)	Capacity (MW)
4-6	2 × j0.3	2 × 100

C. **Transmission Line Addition**

Bus No.	DG Technology	Capacity (MW)
2	WT	4 × 10
4	WT	4 × 10
5	Biomass	4 × 10

D. **Expansion Cost**

Cost Type	Cost (× 10^6 USD)
Total Generator O&M Cost	58.8
Total Generator Investment Cost	3.31
Total Line Investment Cost	60
Total Externality Cost	9.38
Total DG O&M Cost	3.98
Total DG Investment Cost	19
Total Cost	154.47

The addition of DG will reduce demand as DG is treated as a negative load in each demand bus. After expansion, the network is configured differently. Table VII-C shows that only one new line has been added to connect bus 4 and bus 6. This new line consists of two parallel circuits. Its characteristics are detailed in the table. DG implementation also has an impact on the expansion cost of the power system. Table VII-D shows that the investment cost of the new generating unit is slightly higher compared to the previous result and there are additional costs of DG investment and O&M. However, the O&M cost for all the generating units is less because of reducing the investment cost of the transmission line. The externality cost of the generating units is also comparably reduced. The overall expansion of the system with DG implementation is 154.47×10^6 USD. Compared to the previous expansion result, DG implementation will reduce overall expansion cost by 21,27%.

V.3. Simulation Result of IEEE 46 Bus Test System

Simulation with the IEEE 46 bus test system was done using several assumptions related to renewable energy sources. Hydropower can only be built at bus 20, 24, and 42 with a total capacity of 300 MW. PV can only be built at bus 33 and 42. WT is at bus 1, bus 3, and bus 5, while a biomass-based power plant will be built at bus 2, bus 9, and bus 12. The configuration of the installed and prospective transmission line is shown in Table A2 in the appendix. The number of parallel line of installed transmission line is indicated by data of circuit number. While the prospective transmission line has no data in the column of circuit number.

The simulation results of IEEE 46 bus test system without and with DG implementation are shown in Table VIII and Table IX, respectively. Table VIII-A shows that four different types of generator technology were installed, which added 4,015 MW to the system. The total capacity of the existing and newly installed generating units is 8,940 MW.

TABLE VIII
OPTIMAL EXPANSION RESULT OF IEEE 46 BUS WITHOUT DG IMPLEMENTATION

A. **Generator Addition**

Bus No.	Capacity (MW)	Operating Point (MW) Base	Peak
1	2 × 60 (GT)	0	120
7	60 (GT) + 160 (NGCC)	33	220
8	40 (GT)	0	35
20	200 (NGCC) + 1,000 (Nuclear)	1123	1200
23	2 × 200 (NGCC)	400	400
24	135 + 200 (NGCC)	335	335
34	2 × 60 (GT)	0	120
38	2 × 50 (GT)	0	100
39	60 (GT)	0	60
40	50 (GT) + 200 (NGCC)		250
42	200 (NGCC) + 850 (Nuclear)	972	1050
43	2 × 60 (GT)	0	120

B. **Transmission Line Addition**

From-to Bus	Reactance (p.u.)	Capacity (MW)
18-19	1 × j0.0125	1 × 300
19-21	1 × j0.0278	1 × 150
31-41	2 × j0.0278	2 × 150
40-41	1 × j0.0125	1 × 300

C. **Expansion Cost**

Cost Type	Cost ($\times 10^6$ USD)
Total Generator O&M Cost	936
Total Generator Investment Cost	33
Total Line Investment Cost	261
Total Externality Cost	63.2
Total Cost	1,293.2

At expected peak load, there will be a surplus capacity of 29.94%. This surplus capacity is the result of determining the reserve margin with a maximum value of 30.00%. The total investment cost of the new generating units is 33.040×10^6 USD.

Without DG implementation, four transmission lines need to be added, as shown in Table VIII-B. The lines to connect bus 18-19, bus 19-21, and bus 40-14 need to be single circuited lines with a capacity of 300 MW, 150 MW, and 300 MW, respectively. The line to connect bus 31-41 needs to be a double circuited line with a capacity of 2×150 MW. The total cost of new line investment is 261.00×10^6 USD.

The overall cost of system expansion without DG implementation for the IEEE 46 bus test system is $1{,}293.20 \times 10^6$ USD. This overall cost consists of the investment cost of new generating units and transmission lines as previously discussed, the O&M cost of existing and newly installed generating units, and the externality cost of electricity production. Details of the expansion cost are in Table VIII-C.

The optimal expansion planning of the IEEE 46 bus test system with DG implementation is shown in Table IX.

TABLE IX
OPTIMAL EXPANSION RESULT OF IEEE 46 BUS WITH DG IMPLEMENTATION

A. **Generator Addition**

Bus No.	Capacity (MW)	Operating Point Base	Peak
1	60 (GT)	0	60
8	60 (GT) + 135 (NGCC)	58	135
20	200 (NGCC) + 850 (Nuclear)	1,034	1,050
23	180 + 200 (NGCC)	380	380
24	50 (GT) + 200 (NGCC)	200	250
33	60 (GT) + 200 (NGCC)	200	260
34	2 × 60 (GT)	0	120
35	2 × 60 (GT)	0	120
38	40 (GT)	0	40
39	2 × 60 (GT)	0	120
40	40 (GT) + 180 (NGCC)	0	220
42	200 (NGCC) + 1,000 (Nuclear)	1,000	1,200

B. **DG Addition**

Bus No.	DG Technology	Capacity (MW)
1	WT	4 × 6
2	Biomass	4 × 15
5	WT	4 × 6
9	Biomass	15
33	PV	5
42	PV	3 × 5

C. **Transmission Line Addition**

From-to Bus	Reactance (p.u.)	Capacity (MW)
18-19	1 × j0.0125	1 × 300
19-21	1 × j0.0278	1 × 150
32-43	1 × j0.0309	1 × 140

D. **Expansion Cost**

Cost Type	Cost ($\times 10^6$ USD)
Total Generator O&M Cost	932
Total Generator Investment Cost	33
Total Line Investment Cost	150
Total Externality Cost	60.6
Total DG O&M Cost	13.4
Total DG Investment Cost	50.6
Total Cost	1,239.61

It can be seen that the system configuration after expansion with DG implementation has different results compared to expansion without DG implementation. The additional generation units which are needed to supply the expected demand have a total capacity of 4,015 MW. This total capacity is the same as the previous result but with a different configuration due to the different generator technology and location. The overall capacity of the system's generating units and the selected reserve margin also have the same results, which are 8,940 MW and 29.94%, respectively. The total investment cost of the new generating units is 33.00×10^6 USD. Additional detail on the generator technology is shown in Table IX-A. Furthermore, three different types of DG technology need to be built in four buses. WT needs to be built at bus 1 and bus 5 with the capacity of 4×6 MW in each bus. A biomass-based power plant will have to be built at bus 2 and bus 9 with the capacity of 3×15 MW and 2 × 15 MW, respectively. PV will be built at bus 33 and bus 42 with the capacity of 5 MW and 3×15 MW, respectively. The total investment of the newly installed DG is 50.6×10^6 USD.

Compared to expansion without DG implementation, only three additional transmission lines are needed in the system. Lines connecting bus 18-19 and bus 19-21 are still needed for the expansion with DG implementation with the same capacity. An additional line to connect bus 32-43 is needed with a capacity of 140 MW. The total investment for the new transmission lines is 150×10^6 USD. Details on the additional transmission lines are shown in Table IX-C.

The overall expansion cost of the IEEE 46 bus test system is $1,239.60 \times 10^6$ USD. Compared to the previous result, expansion with DG implementation will reduce the overall expansion cost by 4.15%. Overall cost reductions are due to a reduction in the generating O&M cost, transmission line investment, and externality cost. These cost reductions have a greater impact than the additional cost of DG investment and O&M cost. Details of the expansion cost of the IEEE 46 bus test system are shown in Table IX-D.

VI. Conclusion

An integrated model for generation and transmission expansion planning was implemented in a 6-bus and 46-bus system. The objective of the model is to minimize the overall cost of the system by allocating new generating units and transmission lines. The problem was formulated in the form of MILP. The benefits of this formulation are that the exact location and capacity of the new power plant can be determined together with the additional transmission line, and the distributed generation location can be determined based on the potential of each local resource. The simulation results of the integrated model show that the DG implementation will change the network configuration and reduce the overall cost of the system. DG implementation will reduce the overall expansion cost of the electrical power system by 21.27% and 4.15% for Garver's 6 bus system and IEEE 46 bus test system, respectively. Compared to the previous work, the model proposed in this study can be used to perform a comparison of power system expansion planning without and with DG implementation. This model can be used by governments or policy makers in power system expansion to access the correct information regarding suitable DG technologies in each bus or area.

The impact of DG on expansion planning in electrical power systems can be investigated using the multiperiod G-TEP model. The model also can be improved to accommodate stochastic variables. Moreover, the impact of DG on the reliability of power systems from the view of expansion planning can also be investigated with a modification of the proposed model.

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Appendix

TABLE A1
GENERATION AND LOAD DATA OF IEEE 46 BUS TEST SYSTEM

Bus	Generation, MW		Load, MW	Bus	Generation, MW		Load, MW
	Maximum	Level			Maximum	Level	
1	0	0	0	24	0	0	478.2
2	0	0	443.1	25	0	0	0
3	0	0	0	26	0	0	231.9
4	0	0	300.7	27	110	27	0
5	0	0	238	28	400	365	0
6	0	0	0	29	0	0	0
7	0	0	0	30	0	0	0
8	0	0	72.2	31	350	155	0
9	0	0	0	32	250	225	0
10	0	0	0	33	0	0	229.1
11	0	0	0	34	374	111	0
12	0	0	511.9	35	0	0	216
13	0	0	185.8	36	0	0	90.1
14	629	472	0	37	150	106	0

Bus	Generation, MW Maximum	Level	Load, MW	Bus	Generation, MW Maximum	Level	Load, MW
15	0	0	0	38	0	0	216
16	1000	683	0	39	300	111	0
17	525	500	0	40	0	0	262.1
18	0	0	0	41	0	0	0
19	835	387	0	42	0	0	1607.9
20	0	0	1091.2	43	0	0	0
21	0	0	0	44	0	0	79.1
22	0	0	81.9	45	0	0	86.7
23	0	0	458.1	46	350	300	0

TABLE A2
TRANSMISSION LINE DATA OF IEEE 46 BUS TEST SYSTEM

From Bus	To Bus	Circuit Number	Reactance (p.u.)	Capacity (MW)	Line Cost (10^6 USD)	From Bus	To Bus	Circuit Number	Reactance (p.u.)	Capacity (MW)	Line Cost (10^6 USD)
1	2	2	0.1065	270	70.76	20	21	1	0.0125	300	81.78
1	7	1	0.0616	270	43.49	20	23	2	0.0932	270	62.68
2	3	0	0.0125	300	81.78	21	25	0	0.0174	200	21.12
2	4	0	0.0882	270	59.65	22	26	1	0.079	270	54.09
2	5	2	0.0324	270	25.81	23	24	2	0.0774	270	53.08
3	46	0	0.0203	180	24.32	24	25	0	0.0125	300	81.78
4	5	2	0.0566	270	40.46	24	33	1	0.1448	240	93.99
4	9	1	0.0924	270	62.17	24	34	1	0.1647	220	106.11
4	11	0	0.2246	240	142.47	25	32	0	0.0319	140	37.11
5	6	0	0.0125	300	81.78	26	27	2	0.0832	270	56.62
5	8	1	0.1132	270	74.80	26	29	0	0.0541	270	38.94
5	9	1	0.1173	270	77.32	27	29	0	0.0998	270	66.72
5	11	0	0.0915	270	61.67	27	36	1	0.0915	270	61.67
6	46	0	0.0128	200	160.05	27	38	2	0.208	200	132.37
7	8	1	0.1023	270	68.23	28	30	0	0.0058	200	83.31
8	13	1	0.1348	240	87.93	28	31	0	0.0053	200	78.19
9	10	0	0.0125	300	81.78	28	41	0	0.0339	130	39.28
9	14	2	0.1756	220	112.67	28	43	0	0.0406	120	46.70
10	46	0	0.0081	200	108.89	29	30	0	0.0125	300	81.78
11	46	0	0.0125	300	81.78	31	32	0	0.0046	200	70.52
12	14	2	0.074	270	51.06	31	41	0	0.0278	150	32.63
13	18	1	0.1805	220	115.70	32	41	0	0.0309	140	35.96
13	20	1	0.1073	270	71.26	32	43	1	0.0309	140	35.96
14	15	0	0.0374	270	28.84	33	34	1	0.1265	270	82.88
14	18	2	0.1514	240	98.03	34	35	2	0.0491	270	35.91
14	22	1	0.084	270	57.12	35	38	1	0.198	200	126.31
14	26	1	0.1614	220	104.09	36	37	1	0.1057	270	70.25
15	16	0	0.0125	300	81.78	37	39	1	0.0283	270	23.29
16	17	1	0.0078	200	105.05	37	40	1	0.1281	270	83.89
16	28	0	0.0222	180	26.37	37	42	1	0.2105	200	133.88
16	32	0	0.0311	140	36.21	38	42	3	0.0907	270	61.16
16	46	1	0.0203	180	24.32	38	44	1	0.1206	270	79.34
17	19	1	0.0061	200	87.15	39	42	3	0.203	200	129.34
17	32	0	0.0232	170	27.52	40	41	0	0.0125	300	81.78
18	19	1	0.0125	300	81.78	40	42	1	0.0932	270	62.68
18	20	1	0.1997	200	127.32	40	45	0	0.2205	180	139.94
19	21	1	0.0278	150	32.63	41	43	0	0.0139	200	172.84
19	25	0	0.0325	140	37.75	42	43	1	0.0125	300	81.78
19	32	1	0.0195	180	23.42	44	45	1	0.1864	200	119.24
19	46	1	0.0222	180	26.37						-

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