Stochastic Generation-Expansion Planning and Diversification of Energy Transmission Paths

Miloš Pantoš

University of Ljubljana, Faculty of Electrical Engineering,

Tržaška 25, SI-1000, Ljubljana, Slovenia

E-mail: milos.pantos@fe.uni-lj.si, Tel.: +386 1 4768241, Fax: +386 1 4264651

Abstract

The paper addresses a stochastic generation-expansion planning model in the interdependent operation of an electric power system (EPS) and a natural gas system (NGS). The objective of the proposed optimization model is to provide consumers with a reliable electric energy supply by proper generation-expansion planning and diversification of energy transmission paths with minimal investment and operating costs. The proposed method takes into account constraints in the EPS and NGS. The Monte Carlo simulation method is applied to consider random outages of EPS and NGS elements and inaccuracies in the long-term electric load forecasting. A scenario reduction technique is used for reducing the computational burden of a large number of planning scenarios. The EPS and NGS are presented by a direct current (DC) model and a transportation model. The optimization problem is decoupled into a master problem and a subproblem using the Benders decomposition to cope with large-scale problems. The master problem deals with the optimization of investment in new generation units and energy transmission paths. The subproblem comprises a two-level optimization with a decomposed EPS reliability check as the master problem of the subproblem, and a NGS reliability check as the final subproblem. The case studies illustrate the

applications of the proposed stochastic method in a coordinated generation-expansion planning problem when considering uncertainties.

Keywords

Benders decomposition, electric power system, generation expansion planning, Monte Carlo simulation, natural gas system, optimization.

1 NOMENCLATURE

Indices:

A	Superscript index for accompanying energy path
b	Subscript index for load block
C	Superscript index for candidate unit
E	Superscript index for existing unit
i	Subscript index for production unit or well
j	Subscript index for energy transmission path
k	Subscript index for natural gas load
max	Superscript index for maximal value
r	Superscript index of Benders iteration
ref	Subscript index for reference bus
s	Subscript index for scenario
T	Superscript index for matrix transposition
t	Subscript index for year
z	Subscript index for electric load
0	Subscript index for initial state
*	Superscript index for gas-fired unit consumption
^	Superscript index for optimal solution

Variables:

GC	Natural gas flow through compressor
GD	Nodal natural gas load
GL	Natural gas flow through pipeline
PG	Production of generation unit
PL	Power flow on transmission line
Q	Installation status of natural gas pipeline
X	Installation status of generation unit
Y	Installation status of transmission line
Z	Installation status of natural gas compressor

γ	Phase-shifting transformers angle
θ	Bus angle
λ, μ	Dual variables

Parameters and Constants:

a, b	Coefficients of linear load transformation
AC	Number of accompanying compressors
AL	Number of accompanying transmission lines
AP	Number of accompanying pipelines
CG	Number of candidate generation units
CIC	Investment cost of compressor
D	Load distribution factor
d	Discount rate
DT	Duration of load block
E	Yearly electric energy demand
EG	Number of existing generation units
ERE	Random component of peak electric load growth
ERP	Random component of energy demand growth
GIC	Investment cost of pipeline
GW	Objective function of NGS feasibility check
IC	Total investment cost
L	Load at each load block
$LOEP$	Target LOEP, reliability criterion
M	Constant with high value
NB	Number of load blocks
NN	Number of nodes
NS	Number of scenarios
NT	Number of planning years
P	Yearly peak electric load
p, q, r	Gas consumption coefficients of gas-fired unit
PD	Bus electric load
PIC	Investment cost of generating unit
PO	Operation cost of generation unit
RE	Average energy demand growth rate
RP	Average peak electric load growth rate
TIC	Investment cost of transmission line
UQ	Outage status of pipeline
UW	Outage status of natural gas well
UX	Outage status of generation unit
UY	Outage status of transmission line
UZ	Outage status of compressor
W	Objective function of EPS reliability check
x	Reactance of transmission line

Matrices and Vectors:

$\mathbf{A}$	Bus – generation unit incidence matrix

$\mathbf{B}$	Bus – electric load incidence matrix
$\mathbf{C}$	Node – natural gas well incidence matrix
$\mathbf{D}$	Node – natural gas load incidence matrix
$\mathbf{E}$	Node – pipeline incidence matrix
$\mathbf{F}$	Node – compressor incidence matrix
$\mathbf{GC}$	Matrix of gas flows through compressors
$\mathbf{GD}$	Matrix of nodal natural gas consumptions
$\mathbf{GG}$	Matrix of natural gas well productions
$\mathbf{GL}$	Matrix of gas flows through pipelines
$\mathbf{K}$	Bus – transmission line incidence matrix
$\mathbf{PD}$	Matrix of bus electric loads
$\mathbf{PG}$	Matrix of unit productions
$\mathbf{PL}$	Matrix of power flows
$\mathbf{S}_1$, $\mathbf{S}_2$	Matrices of slack variables in EPS
$\mathbf{S}_3$, $\mathbf{S}_4$	Matrices of slack variables in NGS
$\mathbf{1}$	Vector of ones
$\mathbf{0}$	Vector of zeros

Abbreviations:

DC	Direct current
EPS	Electric power system
EUE	Expected unserved energy
FOR	Forced outage rate
ISO	Independent system operator
LOEP	Loss of energy probability
MILP	Mixed integer linear programming
NGS	Natural gas system
NPV	Net present value
O&M	Operation and maintenance

2 INTRODUCTION

Today we are witnessing a growing interdependency of EPSs and NGSs with the number of gas-dependent power plants, such as gas-fired and combined-cycle power plants, increasing. The mayor economic reasons for such a development are energy deficits and rising electricity prices, which motivate investments in gas-dependent power plants. Investment incentives also come from the plants’ high efficiency, low investment cost, lower environmental impact, expeditious permitting and their operation flexibility in comparison with conventional coal plants, [1].

From the economic and technical aspect, the interdependent operation of EPSs and NGSs should result in a higher EPS operation reliability, higher security of energy supply and lower energy prices. However, strong interdependency of energy systems can lead to severe energy crises, such as the 2009 natural gas crisis in Europe, when natural gas transportation paths from East to West Europe were cut off. Industry and millions of homes in Europe were left without the supply of natural gas. In addition, the energy shortage was partly compensated by additional electric energy production, pushing EPSs to their reliability margins, which consequently jeopardized the EPSs' reliability and the security of supply with electric energy. This and similar experience teaches us that in order to assure reliable energy supply the expansion planning process should allow for the possibilities of diversification with respect to different energy sources and transmission paths.

Considering the reliability of electric energy supply, gas-dependent power plants, which convert the energy of natural gas to electric energy, can be located either near consumption centers or near natural gas sources, which are usually located far from consumption centers. In the first case, it is natural gas pipelines that play a major role in ensuring reliable electric energy supply, and in the second case, it is transmission lines. The research presented in this paper addresses the question of optimal generation-expansion planning and diversification of energy transmission paths in order to operate the system reliably by supplying the load economically.

It is necessary to change the traditional concept of EPS planning that considers EPSs as independent from other energy sources and transmission systems. A solution is the coordinated planning of EPSs and NGSs using integrated models of both systems.

Existing literature proposes several integrated models of EPSs and NGSs, addressing different problems in the field of power system operation and planning. Reference [2] computes the maximal generation of combined-cycle power plants applying a two-phase nonlinear optimization model of the EPS and NGS, taking into account the joint reliability of the EPS and NGS. Reference [3] addresses the integrated production and dispatch in EPSs and NGSs, taking into account gas pipelines and capacities constraints. References [4] and [5] propose an integrated EPS and NGS model for optimal power flow calculation with constraints in both systems. A nonlinear energy transformation between natural gas consumption and gas-fired unit production is introduced as the linkage between the EPS and NGS. Similarly, [6] addresses the optimal power flow of multiple energy carriers, introducing the energy hub concept. Applying Lagrangian relaxation and dynamic programming, [7], considers the short-term scheduling of integrated natural gas transmission and hydrothermal power systems. A piecewise linear approximation of nonlinear flow-pressure relations is modeled in the unit-commitment problem, [8]. References [9] and [10] address security-constrained unit commitment with NGS constraints. [9] applies the Benders decomposition to separate the natural gas transmission feasibility-check subproblem from the master unit-commitment problem and the power transmission feasibility-check subproblem. The NGS is presented by a nonlinear model and iteratively solved by the Newton-Raphson method. [10] presents the application of fuel diversity as an effective peak shaving strategy for natural gas demand, which could hedge price volatilities of natural gas and electric power. Finally, [11] and [12] deal with coordinated planning of EPSs and NGSs using integrated models of both systems. In addition to providing a tool for a simultaneous analysis of electricity and gas markets, [11] gives an overview of the main identified parameters and constraints that should be considered in the planning process. A natural gas network model in [12] includes a natural gas well and pipelines, whereas the electrical system includes hydrothermal power generation and a transmission system. A mathematical model of this problem is formulated as a multistage optimization problem where the objective function is to minimize the integrated gas-electricity investment and operation costs.

The following facts served as incentives for the research presented in this paper:

- rising interdependency of EPSs and NGSs due to the increasing number of gas-dependent generating units;
- stakeholder concern in both energy systems for their coordinated operation and development resulting in reliable energy supply at reasonable prices;
- required consideration of the diversification of energy transmission paths in order to provide reliable energy supply;
- necessity to implement integrated models of EPSs and NGSs at the planning stage. Several models mentioned in the preceding paragraph above are applied only in power-system operation, unit commitment and economic dispatch problems;
- incorporation of the stochastic approach into the long-term planning process due to uncertainties and forecast inaccuracies in energy systems, [13];
- necessity to develop an effective method for large-scale optimization, such as long-term EPS planning with interdependent operation of EPSs and NGSs.

This paper thus proposes a stochastic generation-expansion planning method that can be efficiently applied by stakeholders of both energy systems, e.g. a joint regulator or other governmental bodies, a joint-operator, and consumers of electricity and natural gas. The stakeholders’ main goal with respect to energy system development is to ensure reliable future operation of EPSs and NGSs, and reliable energy supply with minimal investment and operating costs. Let us take the Nabucco pipeline project as an example, the new gas bridge from Asia to Europe connecting shareholders from Turkey to Austria. Nabucco Gas Pipeline International GmbH was established in 2004 to take care of financing, public relations, project management and promote studies, but also to implement strategies aimed at encouraging governments and the European Commission to create appropriate incentives for potential investors to take part in the project. Nabucco gained political support from the EU, and an Intergovernmental Agreement was signed in 2009. The method proposed in this paper could serve consultants engaged in the project as an analytical tool. It is appropriate for such tasks since it is based on clear mathematical models and is simple to use, as explained and demonstrated below.

Since the number of gas-dependent power plants is increasing and EPSs and NGSs operate interdependently, the optimization method takes into account constraints in EPSs and NGSs, and with respect to generation-expansion planning, it provides optimal diversification of electric energy and natural gas transmission paths. Compared to [11] and [12], the proposed approach considers the stochastic nature of the problem, i.e. the Monte Carlo method is used to simulate random outages of EPS and NGS elements according to their availabilities as well as inaccuracies in the long-term electric load forecasting. Due to the long period of study and numerous variables, a proper scenario reduction method, [14], [15], is applied to reduce computational effort and to speed up the calculation. Further, to make the proposed optimization method applicable to realistic large-scale models of EPSs and NGSs, the optimization problem is decoupled into the master problem and subproblem using the Benders decomposition. The master problem addresses the investment decision in new generation units and respective transmission paths, and the subproblem comprises a two-level optimization with a decomposed EPS reliability check as the master problem of the subproblem and a NGS reliability check as the final subproblem.

The rest of this paper is organized as follows: Section 3 presents the stochastic formulation and Section 4 the formulation of the proposed generation-expansion planning. Section 5 presents a case study with the interdependent operation of a 6-bus model of an EPS and a 10-node model of a NGS. The conclusions drawn from the study are provided in Section 6.

3 STOCHASTIC FORMULATION

Uncertainties can be classified into two categories: random and nonrandom uncertainties, [13]. Random uncertainties are characteristic of repeatable parameters with certain deviations and allow for a statistical analysis, resulting in probability distribution functions, mean values, standard deviations etc. The uncertainties from this group that are allowed in the proposed generation-expansion planning procedure are uncertainties in outages of generating units, natural gas wells, electric energy and natural gas transmission paths, and inaccuracies in long-term electric energy consumption forecasts. Nonrandom uncertainties and vague data, [13], are not considered in the model.

3.1 Monte Carlo simulation method

The proposed stochastic generation-expansion planning procedure is applied to a long-term horizon. The Monte Carlo method is used to create scenarios that represent all possible system states in that time horizon. The created scenarios consider random characteristics of system components and load growth.

For EPS and NGS elements, their forced outage rates (FORs) are defined according to observations of their past operation. In the simulated scenarios, availabilities of generators, natural gas wells, transmission lines, pipelines and compressors are presented by $UX_{ibt,s}$, $UW_{ibt,s}$, $UY_{jbt,s}$, $UQ_{jbt,s}$, $UZ_{jbt,s}$, respectively, where i, j, b, t, and s denote generation unit or well index, transmission line or pipeline or compressor index, load block, as explained in the text below, year and scenario, respectively. Values 1 and 0 indicate the availability and unavailability of a certain element.

The forecasted yearly consumption is created as suggested in [16]. It is presented by the annual load duration curve that consists of multiple load blocks, each with a constant power, Figure 1.

The annual peak load and the annual energy demand in year t and scenario s, $P_{t,s}$ and $E_{t,s}$, are calculated as the products of the previous year's values, $P_{(t-1),s}$ and $E_{(t-1),s}$, and the yearly growth rates:

$$P_{t,s} = P_{(t-1),s} \cdot (1 + RP + ERP_{t,s}) \,, \tag{1}$$

$$E_{t,s} = E_{(t-1),s} \cdot (1 + RE + ERE_{t,s}) \,. \tag{2}$$

where RP and RE present the average peak load and energy demand growth rate, and $ERP_{t,s}$ and $ERE_{t,s}$ present the random components of the yearly growth rates in year t and scenario s.

The future load in year t, block b, and scenario s, $L_{bt,s}$, is calculated, as suggested in [16], as:

$$L_{bt,s} = a_s \cdot L_{b0} + b_s \,, \tag{3}$$

where L_{b0} presents the base year load, which is defined in advance. Parameters a_s and b_s are calculated as:

$$a_s = \frac{E_{t,s} - H \cdot P_{t,s}}{E_0 - H \cdot P_0} \,, \tag{4}$$

$$b_s = \frac{P_{t,s} \cdot E_0 - P_0 \cdot E_{t,s}}{E_0 - H \cdot P_0} \,. \tag{5}$$

The load in bus z, year t, load block b, and scenario s, $PD_{zbt,s}$, is calculated as the product of the load distribution factor in bus z, D_z, the load in year t, block b, and scenario s, $L_{bt,s}$:

$$PD_{zbt,s} = D_z \cdot L_{bt,s} \, . \tag{6}$$

Instead of the ordinary Monte Carlo simulation method, a low discrepancy Monte Carlo simulation method (lattice) from the group of the so called quasi-Monte Carlo methods is applied in order to accelerate convergence, which is discussed in detail in [16], [17] and [18]. Convergence under the ordinary Monte Carlo method is very slow and its rate is proportionate to the number of sample points generated, in this case to the number of simulated scenarios, i.e. $1/\sqrt{NS}$. The application of a quasi-Monte Carlo technique results in a more uniform behavior of sample points, and the convergence rate can reach $1/NS$, resulting in faster convergence.

An *n*-point lattice rule of rank *r* takes the form:

$$\left\{ \sum_{i=1}^{r} \frac{k_i}{n_i} \mathbf{v}_i \mod 1,\ k_i = 0, 1, \ldots, n_i - 1,\ i = 1, \ldots, r \right\} \tag{7}$$

for linearly independent integer vectors $\mathbf{v}_1,\ldots,\mathbf{v}_r$ and integers $n_1,\ldots,n_r \geq 2$. Taking the remainder modulo 1 (the rank-1 case) means taking the fractional part of a number, i.e. $x \bmod 1 = x - \lfloor x \rfloor$, and the operation is applied separately to each coordinate of the vector. To ensure that this set does indeed contain n_i distinct points, it is required that n_i and the elements of $\mathbf{v}_i$ have 1 as their greatest common divisor.

3.2 Scenario reduction

Computational requirements for solving scenario-based optimization models depend on the number of scenarios. An effective scenario reduction method can therefore be essential for solving large-scale systems. The reduction technique is a scenario-based approximation with a smaller number of scenarios and a reasonably good approximation of the original system. In the proposed generation-expansion planning problem the scenario reduction method based on the likelihood estimation is described in [16] and [14], and it is applied using the GAMS/SCENRED tool, [15]. Stochastic scenarios are clustered into subsets of prescribed cardinality or accuracy. In the process new probabilities to the preserved scenarios are assigned, such that the corresponding reduced probability measure is the closest to the original measure in terms of a certain probability distance between them. The probability distance trades off scenario probabilities and distances of scenario values. In the context of stochastic power management models, the Kantorovich distance of (multivariate) probability distributions is used.

4 GENERATION-EXPANSION PLANNING WITH NGS CONSTRAINTS

After data preparation, scenario generation and scenario reduction, the proposed generation-expansion planning process is decomposed using the Benders method into the master problem and its subproblem as presented in Figure 2.

The master problem optimizes the investments in new generation units and consequently in energy transmission paths needed for the evacuation of the electric energy produced in an EPS and for the supply of natural gas as a fuel to gas-fired generation units. The optimization includes operating costs in order to find the most cost-effective solution. $X_{i,t}$, $Y_{j,t}$, $Q_{j,t}$ and $Z_{j,t}$ in Figure 2 denote the installation statuses of generation unit i and corresponding energy transmission paths, i.e., transmission line j, natural-gas pipeline j and compressor j, in year t.

The subproblem addresses the EPS reliability check, taking into account the natural gas constraints of a NGS. The subproblem comprises a two-level optimization with the decomposed EPS reliability check as the master problem of the subproblem and the NGS feasibility check as the final subproblem. The Benders decomposition is applied here in order to decouple a large-scale optimization problem into two problems of smaller dimensions.

4.1 Generation-expansion planning problem

Generation-expansion planning is solved in the master problem presented in Figure 2. The regulator or an independent system operator (ISO) body performs investment optimization using the mixed integer linear programming (MILP) technique, where the objective is achieving minimal investment and operating costs for existing and candidate generation units. The optimization problem is formulated as:

$$Min\left\{\begin{array}{l}\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{EG}\frac{DT_b\cdot PG_{ibt}^{E}\cdot PO_i^{E}}{(1+d)^{(t-1)}}+\\ +\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{CG}\frac{DT_b\cdot PG_{ibt}^{C}\cdot PO_i^{C}}{(1+d)^{(t-1)}}+\\ +\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{CG}\frac{PIC_i\cdot X_{it}}{(1+d)^{(t-1)}}+\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{j=1}^{AL_i}\frac{TIC_j\cdot Y_{jt}}{(1+d)^{(t-1)}}+\\ +\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{j=1}^{AP_i}\frac{GIC_j\cdot Q_{jt}}{(1+d)^{(t-1)}}+\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{j=1}^{AC_i}\frac{CIC_j\cdot Z_{jt}}{(1+d)^{(t-1)}}\end{array}\right\}, \tag{8}$$

s.t.

$$0\le PG_{ibt}^{E}\le PG_i^{E,\max}\qquad \forall i,\forall b,\forall t, \tag{9}$$

$$0\le PG_{ibt}^{C}\le PG_i^{C,\max}\cdot X_{it}\qquad \forall i,\forall b,\forall t, \tag{10}$$

$$X_{it}\le X_{i(t+1)}\qquad \forall i,\forall t, \tag{11}$$

$$Y_{jt}=X_{it}\qquad \forall j,\forall i,\forall t, \tag{12}$$

$$Q_{jt}=X_{it}\qquad \forall j,\forall i,\forall t, \tag{13}$$

$$Z_{jt}=X_{it}\qquad \forall j,\forall i,\forall t. \tag{14}$$

The first two terms in the objective function (8) are the operating costs of the existing and new generation units. It is important to note that the operating costs are linearized in order to retain the optimization model linear. This assumption is tolerable for gas-fired production units since fuel costs represent the largest part of the total operating costs. The third term represents the investment cost of new generation units. The other terms represent the investment cost of corresponding energy transmission paths that are required for the fuel supply of gas-fired generation units and for the injection of produced electric energy into the EPS, Figure 3.

Constraints (9) and (10) are the capacity limits for the existing and candidate production units. Constraint (11) is to maintain the installation status of generating units. Constraints (12)–(14) assure the investments in energy paths that are required as mentioned above. Consequently, the total investment cost related to generation unit *i* in year *t* can be expressed as:

$$IC_i = PIC_i + \sum_{j=1}^{AL_i} TIC_j + \sum_{j=1}^{AP_i} GIC_j + \sum_{j=1}^{AC_i} CIC_j \,, \tag{15}$$

and can be included in the objective as:

$$Min\left\{\begin{array}{l} \displaystyle\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{EG}\frac{DT_b \cdot PG_{ibt}^{E} \cdot PO_i^{E}}{(1+d)^{(t-1)}} + \\ \displaystyle + \sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{CG}\frac{DT_b \cdot PG_{ibt}^{C} \cdot PO_i^{C}}{(1+d)^{(t-1)}} + \\ \displaystyle + \sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{CG}\frac{IC_i \cdot X_{it}}{(1+d)^{(t-1)}} \end{array}\right\} . \tag{16}$$

The decision variables of the master problem are PG_{ibt}^{E}, PG_{ibt}^{C}, and binary variables X_{it}, Y_{jt}, Q_{jt}, Z_{jt}, but only optimal installation statuses $\hat{X}_{it}$, $\hat{Y}_{jt}$, $\hat{Q}_{jt}$ and $\hat{Z}_{jt}$ are submitted to the subproblem, Figure 2.

4.2 Reliability check problem

The purpose of the reliability check problem is to evaluate the reliability of the planned EPS with natural gas constraints in NGS. In order to tackle large-scale optimization problems of realistic energy systems, the reliability check problem is decoupled into a lower level master problem dealing with the EPS and a lower level subproblem focused on the NGS feasibility check, Figure 2.

4.2.1 EPS reliability check

This analysis measures system reliability applying Loss of Energy Probability (LOEP). LOEP is defined as the ratio of the expected unserved energy (EUE) to the total electric energy demand of the EPS, [19], [20]. The reliability check problem at load block *b*, year *t*, Benders iteration *r* and scenario *s* is formulated as:

$$Min\left\{W_{bt,s}^{r}=\mathbf{1}^{\mathrm{T}}\cdot\mathbf{S}_{\mathbf{1},s}+\mathbf{1}^{\mathrm{T}}\cdot\mathbf{S}_{\mathbf{2},s}\right\},\tag{17}$$

s.t.

$$\mathbf{A}\cdot\mathbf{PG}_{s}-\mathbf{B}\cdot\mathbf{PD}_{s}-\mathbf{K}\cdot\mathbf{PL}_{s}+\mathbf{S}_{\mathbf{1},s}-\mathbf{S}_{\mathbf{2},s}=\mathbf{0}\,,\tag{18}$$

$$PL_{jbt,s}^{E}=\frac{\theta_{jmbt,s}^{E}-\theta_{jnbt,s}^{E}-\gamma_{jbt,s}^{E}}{x_{j}^{E}}\qquad\forall j\,,\tag{19}$$

$$\left|PL_{jbt,s}^{A}-\frac{\theta_{jmbt,s}^{A}-\theta_{jnbt,s}^{A}-\gamma_{jbt,s}^{A}}{x_{j}^{A}}\right|\le M\cdot\left(1-\hat{Y}_{jt}^{A}\right)\qquad\forall j\,,\tag{20}$$

$$\left|PL_{jbt,s}^{E}\right|\le PL_{j}^{E,\max}\cdot UY_{jbt,s}^{E}\qquad\forall j\,,\tag{21}$$

$$\left|PL_{jbt,s}^{A}\right|\le PL_{j}^{A,\max}\cdot UY_{jbt,s}^{A}\cdot\hat{Y}_{jt}\qquad\forall j\,,\tag{22}$$

$$\gamma_{j}^{E,\min}\le\gamma_{jbt,s}^{E}\le\gamma_{j}^{E,\max}\,,\tag{23}$$

$$\gamma_{j}^{A,\min}\le\gamma_{jbt,s}^{A}\le\gamma_{j}^{A,\max}\,,\tag{24}$$

$$0\le PG_{ibt,s}^{E}\le PG_{i}^{E,\max}\cdot UX_{ibt,s}^{E}\qquad\forall i\,,\tag{25}$$

$$0\le PG_{ibt,s}^{C}\le PG_{i}^{C,\max}\cdot UX_{ibt,s}^{C}\cdot\hat{X}_{jt}\quad(\lambda_{ibt,s}^{r})\quad\forall i\,,\tag{26}$$

$$\mathbf{S}_{\mathbf{1},s}\ge\mathbf{0}\,,\tag{27}$$

$$\mathbf{S}_{\mathbf{2},s}\ge\mathbf{0}\,,\tag{28}$$

$$\theta_{ref}=0\,.\tag{29}$$

The decision variables are $\mathbf{PG}_s$ and slack variables $\mathbf{S}_{\mathbf{1},s}$ and $\mathbf{S}_{\mathbf{2},s}$. However, only the $\mathbf{PG}_s$ related to the gas-fired production units are submitted to the NGS feasibility check. Once the EPS feasibility check problem is solved and the NGS is feasible for every scenario, the Benders cut of the outer loop in Figure 2 at iteration *r* is generated when the LOEP at load block *b* in year *t* is larger than the target LOEP. The LOEP at load block *b* in year *t* is calculated by dividing the expected value of the objective function $W_{bt,s}^{r}$ times the duration of the load block DT_b with the expected load $L_{bt,s}$ times the duration of the load block DT_b, [16]:

$$LOEP_{bt}=\frac{\sum_{s=1}^{NS}PR_{s}\cdot W_{bt,s}^{r}\cdot DT_{b}}{\sum_{s=1}^{NS}PR_{s}\cdot L_{bt,s}\cdot DT_{b}}\,.\tag{30}$$

If the reliability criterion is not satisfied, the Benders cut is formed as:

$$\sum_{s=1}^{NS} PR_s \cdot W_{bt,s}^{r} + \sum_{s=1}^{NS}\sum_{i=1}^{CG}\left(PR_s \cdot \lambda_{ibt,s}^{r} \cdot PG_i^{C,\max} \cdot UX_{ibt,s}^{C} \cdot \left(X_{it} - \hat{X}_{it}\right)\right) \le LOEP \cdot \sum_{s=1}^{NS} PR_s \cdot L_{bt,s} \, , \tag{31}$$

and sent through the outer Benders loop to the master problem as an additional constraint for the next iteration.

4.2.2 NGS feasibility check

The electric power generated by a gas-fired production unit is a nonlinear function of natural gas supply, which is presented as a natural gas load in the NGS, thus generation unit *i* with electric power production $PG_{ibt,s}$ in year *t*, block *b* and scenario *s* has to be supplied with $GD_{kbt,s}^{*}$ of natural gas from node *k* in the NGS:

$$GD_{kbt,s}^{*} = p_i + q_i \cdot PG_{ibt,s} + r_i \cdot PG_{ibt,s}^{2} \, , \tag{32}$$

where coefficients p_i, q_i and r_i depend on power plant characteristics.

Each gas-fired production unit has its maximal and minimal technical boundary, (25) and (26), and its electric energy production also depends on natural gas contracts with natural gas suppliers, which may present additional limitations to the production capacity. For simplicity's sake gas contract constraints are not explicitly addressed in the paper but it is presumed that generation capacities in (25) and (26) already incorporate possible additional natural gas contract limitations.

The optimization problem of the NGS feasibility check at load block *b*, year *t*, Benders iteration *r* and scenario *s* is formulated as:

$$Min\left\{GW_{bt,s}^{r} = \mathbf{1}^{\mathrm{T}} \cdot \mathbf{S}_{\mathbf{3},s} + \mathbf{1}^{\mathrm{T}} \cdot \mathbf{S}_{\mathbf{4},s}\right\}, \tag{33}$$

s.t.

$$\mathbf{C} \cdot \mathbf{GG}_s - \mathbf{D} \cdot \mathbf{GD}_s - \mathbf{E} \cdot \mathbf{GL}_s - \mathbf{F} \cdot \mathbf{GC}_s + \mathbf{S}_{\mathbf{3},s} - \mathbf{S}_{\mathbf{4},s} = \mathbf{0} \, , \tag{34}$$

$$0 \le GD_{kbt,s} \le GD_{kbt,s}^{*} \quad (\mu_{kbt,s}^{r}) \quad \forall k \, , \tag{35}$$

$$\left|GL_{jbt,s}^{E}\right| \le GL_j^{E,\max} \cdot UQ_{jbt,s}^{E} \qquad \forall j \, , \tag{36}$$

$$\left|GL_{jbt,s}^{A}\right| \le GL_j^{A,\max} \cdot UQ_{jbt,s}^{A} \cdot \hat{Q}_{jt} \qquad \forall j \, , \tag{37}$$

$$\left|GC_{jbt,s}^{E}\right| \le GC_j^{E,\max} \cdot UZ_{jbt,s}^{E} \qquad \forall j \, , \tag{38}$$

$$\left|GC_{jbt,s}^{A}\right| \le GC_j^{A,\max} \cdot UZ_{jbt,s}^{A} \cdot \hat{Z}_{jt} \qquad \forall j \, , \tag{39}$$

$$0 \le GG_{ibt,s} \le GG_i^{\max} \cdot UW_{ibt,s} \qquad \forall i\,, \tag{40}$$

$$\mathbf{S}_{\mathbf{3},s} \ge \mathbf{0}\,, \tag{41}$$

$$\mathbf{S}_{\mathbf{4},s} \ge \mathbf{0}\,. \tag{42}$$

The decision variables are $\mathbf{GG}_s$, $\mathbf{GD}_s$, $\mathbf{GL}_s$, $\mathbf{GC}_s$, and slack variables $\mathbf{S}_{\mathbf{3},s}$ and $\mathbf{S}_{\mathbf{4},s}$. If a non-zero objective function $GW_{bt,s}^r$ is obtained, the available natural gas resources cannot satisfy natural gas transmission limits and/or natural gas demands of gas-fired production units. Consequently, the Benders cut of the inner loop in Figure 2 is formed as:

$$GW_{bt,s}^r + \sum_{k=1}^{NN} \mu_{kbt,s}^r \cdot D_k \cdot \left(GD_{kbt,s} - \hat{GD}_{kbt,s}^{\,r} \right) \le 0\,. \tag{43}$$

Inserting (32) in (43) for gas-fired units forms power constraints and adds them to the EPS reliability check, (17)–(29), for the next iteration.

As presented, the NGS feasibility check is performed using the transportation model of the NGS, (33)–(42), considering only the capacities of natural gas wells and transportation capacities of pipelines and compressors. Detailed NGS models that also consider pressure constraints and the optimization of controllable compressors, e.g. the model in [9], would be inappropriate for long-term expansion planning problems since the exact structure of the NGS over the planning horizon is not known, as the NGS is continuously expanding according to the long-term planning program. Detailed NGS models are applicable in short-term and real-time analyses, such as unit-commitment and economic-dispatch problems.

5 CASE STUDY

The proposed method for generation-expansion planning and diversification of energy transmission paths is tested on a 6-bus model of an EPS and a 10-node model of a NGS, as presented in Figure 4. The 6-bus EPS consists of 3 natural gas independent generators, 3 loads and 7 lines. In the 10-node NGS, 7 loads are supplied by 3 natural gas wells through 9 pipelines and 2 compressors. The detailed parameters of the used EPS and NGS models are given in Tables 1–4.

Electric loads are located at buses 3, 4 and 5. The average peak-load and energy-demand growth rates *RP* and *RE* are 5 % per year. The random components in peak-load and energy-demand growth rate, $ERP_{t,s}$ and $ERE_{t,s}$, have a normal distribution with 0 mean and 0.01 standard deviation. The annual load duration curve, Figure 1, consists of 4 load blocks with constant powers. Their values in the initial year and block durations are presented in Table 5.

The case study is applied to a 10-year planning horizon with a 5 % target LOEP for all load blocks. In addition to the 3 existing production units in Figure 4, 14 candidate gas-dependent generation units are considered in the planning process. They are divided into two groups:

- **group N** with 7 candidate units, N1–N7 in Figure 5, located close to natural gas sources with the required transmission lines for the power injection into the EPS.
- **group E** with 7 candidate units, E1–E7 in Figure 5, located close to electric energy consumption centers with required pipelines to provide fuel from the NGS.

Reference [21] addresses the comparison of the capital cost of energy transmission via natural gas pipelines and overhead electric wires, comparing two generic infrastructure scenarios. In the first scenario, 100 miles of a 500 kV electric transmission line are required in order to deliver 1,500 MW of electric power from remote generators to consumers. In the second scenario, 100 miles of a 20” gas pipeline are built to fuel a 1500 MW generation facility located near the load center. The exact capital cost breakdown and assumptions are provided in [21] and the capital (investment) costs are overviewed in Tables 6 and 7.

The overall cost comparison is provided in Table 8, including operation and maintenance (O&M) costs. The 12 % interest rate is used for this study as being generally representative of private sector borrowing. The assumed lifetime of the equipment is 40 years and the 65 % load factor approximates the typical electric transmission scenario as reported in [21].

References [22] and [23] provide information on the key factors affecting the economics of electricity production using a range of technologies. Based on this reference, the last row in Table 8 presents the cost structure for a typical gas-fired generation unit. Fuel costs are estimated as 80 % of total annual costs and O&M costs represent 2 % of the annual investment. Data from Table 8 are used for all candidate generators and energy transmission paths in groups N and E. The parameters are presented in Table 9.

The investment costs of additional transmission lines are slightly higher compared to the investment costs of additional pipelines, thus candidate generators near the fuel sources, i.e. generators in group N, have higher total investment costs compared to generators in group E. The operation costs of generators in group E are minimally higher compared to the operation costs of generators in group N due to the different operation costs of transmission lines and pipelines. Other parameters are equal for both generators in each pair, e.g. generators N1 and E1, facilitating clear conclusions of the simulation.

As discussed in Introduction, due to the interdependency of EPSs and NGSs, the EPS reliability, security of supply with electric energy and, consequently, planning decisions depend on conditions in NGSs as well. Thus, 3 cases are considered in the study to show the effectiveness of the proposed model. Each case has specific FORs for all additional natural gas transmission pipelines between the NGS and EPS, Figure 5, required to supply production units E1–E7 with fuel. The values are presented in Table 10.

FORs for all additional transmission lines between NGS and EPS, Figure 5, required for the injection of produced power by units N1–N8 are constant in all cases end equal 0.5 %. The test cases are designed in such a way to show the descending reliability of natural gas transportation paths between gas sources and gas-fired units. This results in the need to search for alternative ways of providing energy to consumers in the EPS. In this case study the alternative was, obviously, the transmission lines.

For each case 1,000 scenarios are created using the low-discrepancy Monte Carlo simulation, with each scenario representing outages of generation units, natural gas wells, transmission lines, pipelines, compressors and random components of electric load, i.e. ERPs and EREs. The computation time for the scenario-based problem depends on the number of scenarios, thus SCENRED/GAMS for scenario reduction is applied to reduce the number of scenarios from 1,000 to 10. Table 11 shows the probabilities of the remaining scenarios for each simulated case.

Tables 12–14 present the installation years of candidate production units for all cases. The number of installed units increases during the planning horizon in accordance with consumption growth, providing for a reliable operation of the EPS. In all simulated cases, due to lower investment costs generators from group E are initially installed. If the target LOEP is not reached by those units, some of the units from group N are additionally installed.

The installation dynamics in the simulated cases, Tables 4–6, show that the optimization model proposes the installation of expensive units in group N also in earlier years when the reliability of natural gas transportation paths is lower. Figure 6 presents the total number of operation years of units in groups E and N. Unreliable pipelines and consequently unreliable generators in group E require an additional investment in the reliable group N generators and corresponding transmission lines in order to meet the LOEP target. The result is a more diverse set of energy transmission paths proposed for installation in the planning period.

The results in Figure 7 present the total capacities of all installed units, including the existing units, for each planning year. Since the availability of generation units supplied with natural gas, i.e. units in group E, is decreasing through simulated cases, additional units have to be installed in order to meet reliability requirements. Consequently the total costs expressed with net present value (NPV) shown in Table 15 are the highest in case 3.

6 CONCLUSIONS

The paper proposes the stochastic long-term generation-expansion planning formulation applying the Monte Carlo simulation and scenario reduction technique. Uncertainties in the availability of EPS and NGS elements and inaccuracies in electric load forecasting are considered through the planning horizon. The Benders decomposition is applied in two loops in order to reduce computational requirements and to enable the solving of large-scale problems. The effectiveness of the proposed formulation is demonstrated on the case of the interdependent operation of the 6-bus EPS and the 10-node NGS. Simulations show that the proposed method successfully performs generation-expansion and diversification of available energy transmission paths.

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FIGURES AND TABLES

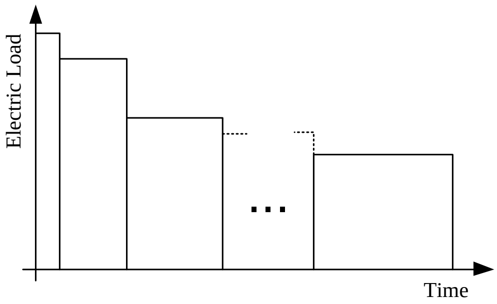

Figure 1: Annual load duration curve

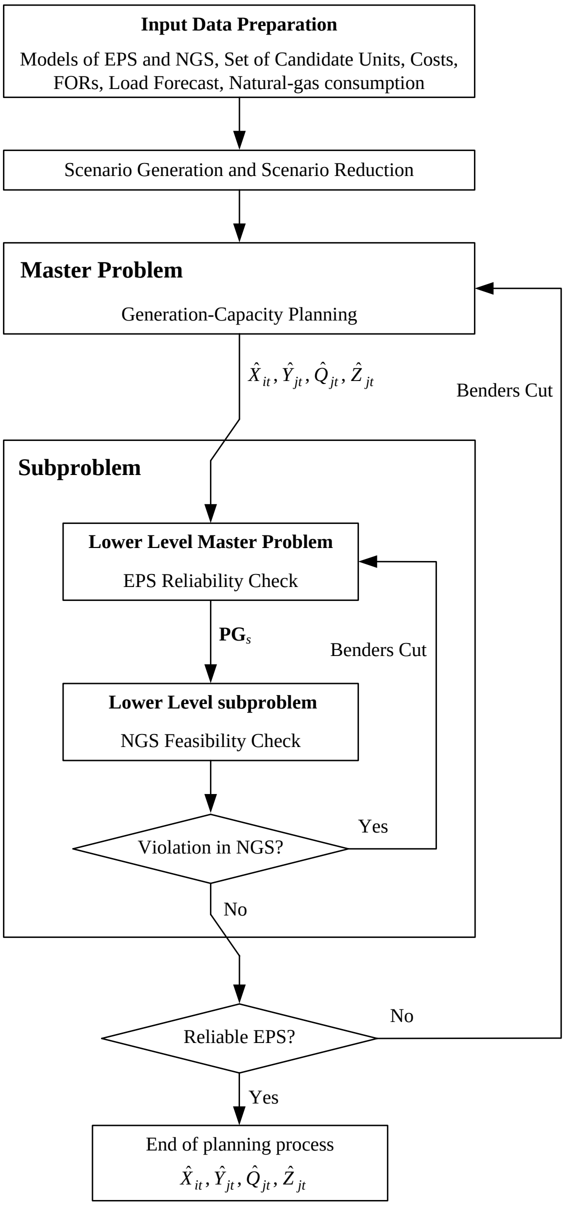

Figure 2: Flow chart of generation-expansion planning procedure

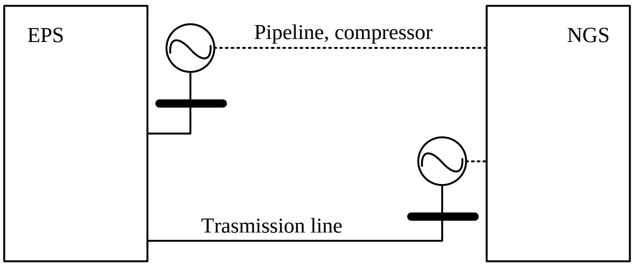

Figure 3: Energy transmission paths between the EPS and NGS

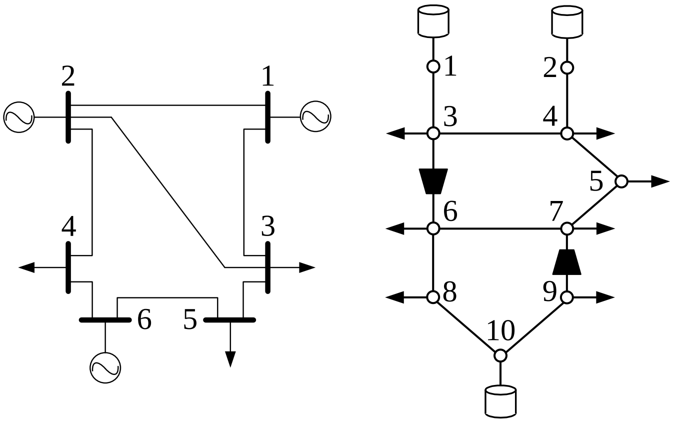

Figure 4: 6-bus model of the EPS and 10-node model of the NGS

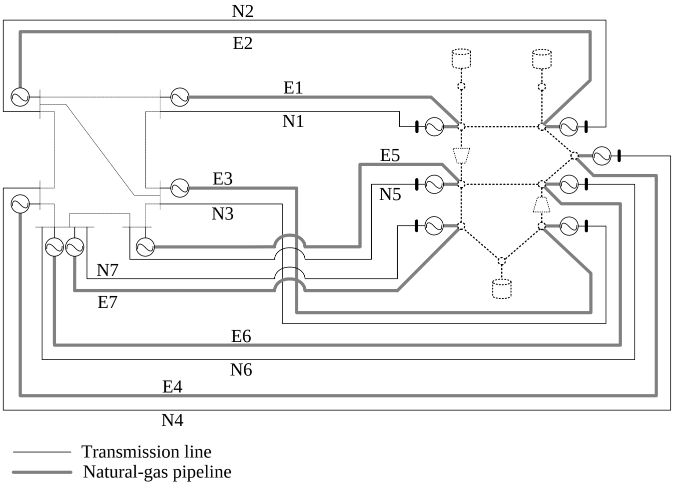

Figure 5: Candidate production units with required energy transmission paths

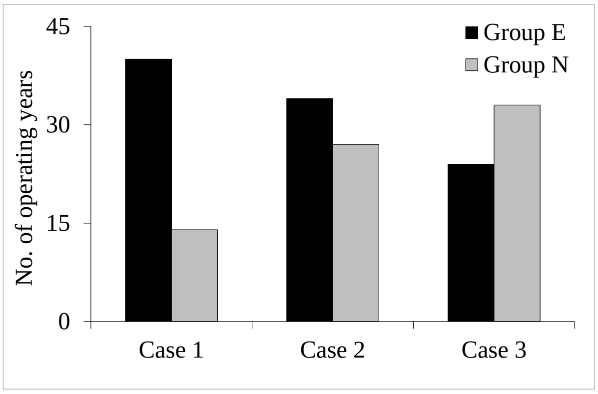

Figure 6: Total operation years of units in groups E and N

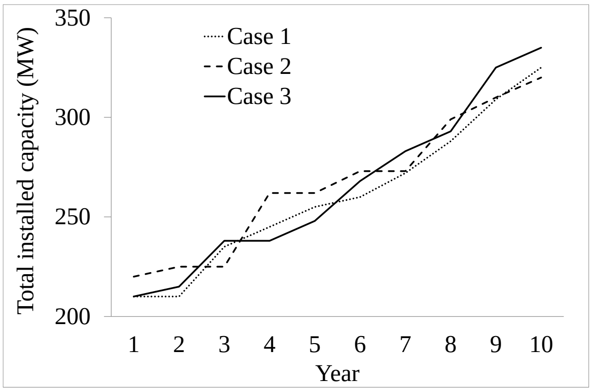

Figure 7: Total installed capacities in MW

Table 1: Parameters of the existing generators and loads in the 6-bus EPS

Bus	Capacity (MW)	Load Distrib. Factor	FOR (%)	Operation cost ($/MWh)
1	70	0.0	2.0	69.876
2	70	0.0	2.0	69.876
3	0	0.4	0.0	0.000
4	0	0.3	0.0	0.000
5	0	0.3	0.0	0.000
6	70	0.0	2.0	69.876

Table 2: Line parameters in the 6-bus EPS

From bus	To bus	x_j	Capacity (MW)	FOR (%)
1	2	0.170	100	0.1
2	3	0.037	100	1.0
1	4	0.158	100	1.0
2	4	0.197	100	1.0
4	5	0.037	100	1.0
5	6	0.140	100	1.0
3	6	0.017	100	1.0

Table 3: Gas production and fixed consumption in the 10-node NGS

Node	Well capacity (kcf/h)	Load (kcf/h)	FOR (%)	To EPS bus
1	4000	0	1.0	-
2	4000	0	1.0	-
3	0	1000	0.0	1
4	0	1000	0.0	2
5	0	1000	0.0	4
6	0	1000	0.0	5
7	0	1000	0.0	6
8	0	1000	0.0	6
9	0	1000	0.0	3
10	4000	0	1.0	-

Table 4: Pipeline and compressor parameters in the 10-node NGS

From node	To node	Type	Capacity (MW)	FOR (%)
1	3	Pipeline	4000	0.3430
2	4	Pipeline	4000	0.3052
3	4	Pipeline	3000	0.3133
4	5	Pipeline	3000	0.3240
5	7	Pipeline	3000	0.3026
6	7	Pipeline	3000	0.3146
6	8	Pipeline	3000	0.2736
8	10	Pipeline	3000	0.2635
9	10	Pipeline	3000	0.3135
3	6	Compressor	3000	0.2807
7	9	Compressor	3000	0.3157

Table 5: Duration and powers of load blocks

Subperiod	1	2	3	4
Duration (%)	1	29	50	20
Load (MW)	200	160	120	100

Table 6: Capital costs of power line

Material, design and construction of 500 kV power line (%)	65.04	
Environmental and land (%)	16.91	
Upgrade at existing substation (%)	1.63	
New substation at generator (%)	7.64	
Communications equipment and fiber (%)	6.50	
Voltage stabilizing equipment - shunt capacitor (%)	2.28	
Total investment cost ($/100 miles)		**199,875,000**

Table 7: Capital costs of the gas pipeline

Material, design and construction of 20" pipeline (%)	61.50	
Environmental and land (%)	14.79	
Road and railroad crossings (%)	3.98	
Mainline valve (%)	1.39	
Internal inspection tool (Pig) launcher and receiver (%)	0.50	
Compression installed (%)	17.83	
Total investment cost ($/100 miles)		**100,400,000**

Table 8: Overall cost comparison for the power line and the gas pipeline

	Power line	Gas pipeline	Gas-fired unit
Capacity (MW)	1,500	1,500	160
Length (mile)	100	100	/
Investment cost ($)	199,875,000	100,400,000	128,000,000
Lifetime (year)	40	40	40
Cost of capital (%/year)	12	12	12
Annual pament ($/year)	24,245,562.16	12,178,884.01	15,526,864.07
Annual payment per kW ($/kW/year)	16.16	8.12	97.04
Annual payment per MWh ($/MWh/year)*	2.84	1.43	17.04
Annual O&M costs ($/year)***	519,000.00	1,000,000.00	388,171.60
Annual O&M costs per kW ($/kW/year)	0.35	0.67	1.94
Annual O&M costs per MWh ($/MWh/year	0.06	0.12	0.34
Annual Fuel costs ($/year)**	/	/	63,349,605.42
Annual fuel costs per kW ($/kW/year)	/	/	395.94
Annual fuel costs per MWh ($/MWh/year)*	/	/	69.54
Total annual costs ($/year)	24,764,562.16	13,178,884.01	79,264,641.10
Total annual costs per kW ($/kW/year)	16.51	8.79	495.40
Total annual costs per MWh ($/MWh/year)	2.90	1.54	87.00

* Load factor: 0.65

** 80 % of total annual costs

*** For gas-fired unit: 2 % of annual payment

Table 9: Parameters of candidate energy transmission paths including production units

ID	EPS bus	NGS node	Capacity (MW)	Operation cost ($/MWh)	Ivestment cost ($/kW/year)	FOR (%)	p_i (kcf/h)	q_i (kcf/h/MW)	r_i (kcf/h/MW^2)
N1	1	3	16	69.937	113.207	1.0	0.000	0.012	1.050
E1	1	3	16	69.993	105.162	1.0	0.000	0.012	1.050
N2	2	4	10	69.937	113.207	1.0	0.000	0.022	1.100
E2	2	4	10	69.993	105.162	1.0	0.000	0.022	1.100
N3	3	9	11	69.937	113.207	1.0	0.000	0.014	1.030
E3	3	9	11	69.993	105.162	1.0	0.000	0.014	1.030
N4	4	5	12	69.937	113.207	1.0	0.000	0.011	0.960
E4	4	5	12	69.993	105.162	1.0	0.000	0.011	0.960
N5	5	6	10	69.937	113.207	1.0	0.000	0.021	0.870
E5	5	6	10	69.993	105.162	1.0	0.000	0.021	0.870
N6	6	7	5	69.937	113.207	1.0	0.000	0.013	0.980
E6	6	7	5	69.993	105.162	1.0	0.000	0.013	0.980
N7	6	8	10	69.937	113.207	1.0	0.000	0.023	1.070
E7	6	8	10	69.993	105.162	1.0	0.000	0.023	1.070

Table 10: FORs of additional pipelines and transmission lines

	Case 1	Case 2	Case 3
FOR of pipelines (%)	10.00	15.00	30.00
FOR of transmission lines (%)	0.50	0.50	0.50

Table 11: Scenario probabilities after scenario reduction

Scen.	Probabilities PR_s		
	Case 1	Case 2	Case 3
1	0.073	0.100	0.036
2	0.086	0.147	0.105
3	0.329	0.060	0.074
4	0.106	0.115	0.043
5	0.035	0.136	0.067
6	0.081	0.098	0.046
7	0.036	0.068	0.233
8	0.071	0.102	0.138
9	0.039	0.097	0.140
10	0.144	0.077	0.118

Table 12: Candidate production unit installation year in case 1

Prod. Unit	Year									
	1	2	3	4	5	6	7	8	9	10
E1	0	0	0	0	0	0	0	1	1	1
E2	0	0	1	1	1	1	1	1	1	1
E3	0	0	0	0	0	0	0	0	1	1
E4	0	0	0	0	0	0	1	1	1	1
E5	0	0	0	1	1	1	1	1	1	1
E6	0	0	1	1	1	1	1	1	1	1
E7	0	0	1	1	1	1	1	1	1	1
N1	0	0	0	0	0	0	0	0	0	1
N2	0	0	0	0	0	0	0	0	1	1
N3	0	0	0	0	0	0	0	0	0	0
N4	0	0	0	0	0	0	0	0	0	0
N5	0	0	0	0	0	0	0	0	0	0
N6	0	0	0	0	0	1	1	1	1	1
N7	0	0	0	0	1	1	1	1	1	1

Table 13: Candidate production unit installation year in case 2

Prod. Unit	Year									
	1	2	3	4	5	6	7	8	9	10
E1	0	0	0	0	0	0	0	1	1	1
E2	1	1	1	1	1	1	1	1	1	1
E3	0	0	0	0	0	0	0	0	1	1
E4	0	0	0	0	0	0	0	0	0	0
E5	0	0	0	1	1	1	1	1	1	1
E6	0	1	1	1	1	1	1	1	1	1
E7	0	0	0	0	0	0	0	1	1	1
N1	0	0	0	0	0	0	0	0	0	0
N2	0	0	0	0	0	0	0	0	0	1
N3	0	0	0	0	0	1	1	1	1	1
N4	0	0	0	1	1	1	1	1	1	1
N5	0	0	0	0	0	0	0	0	0	0
N6	0	0	0	1	1	1	1	1	1	1
N7	0	0	0	1	1	1	1	1	1	1

Table 14: Candidate production unit installation year in case 3

Prod. Unit	Year									
	1	2	3	4	5	6	7	8	9	10
E1	0	0	0	0	0	0	0	0	1	1
E2	0	0	0	0	0	0	0	1	1	1
E3	0	0	0	0	0	0	0	0	0	0
E4	0	0	0	0	0	0	0	0	0	0
E5	0	0	0	0	1	1	1	1	1	1
E6	0	1	1	1	1	1	1	1	1	1
E7	0	0	0	0	0	0	1	1	1	1
N1	0	0	0	0	0	0	0	0	1	1
N2	0	0	0	0	0	0	0	0	0	1
N3	0	0	1	1	1	1	1	1	1	1
N4	0	0	1	1	1	1	1	1	1	1
N5	0	0	0	0	0	1	1	1	1	1
N6	0	0	0	0	0	0	1	1	1	1
N7	0	0	0	0	0	1	1	1	1	1

Table 15: NPV of total cost

	Case 1	Case 2	Case 3
NPV of total cost (mio $)	24,390	23,931	29,762