Economic Analysis of a Pumped Storage Project for Iran Generating System Based on a Dynamic Modeling

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Abstract-This paper proposes a dynamic model for evaluation of a Pumped Storage Project (PSP) . The optimal expansion policy is determined by considering different alternatives (Types of units: Rodbar PSP(RPSP), Steam Turbine , 2 types of Gas Turbine and a Combined Cycle) . Based on this model dynamic assessment of different alternatives (over a 20 years period and with a target Loss Of Load Probability (LOLP)) provides economic justification for RPSP.

1. Introduction

A new Dam construction Program in Rodbar-e-Lorestan area raised a series of questions: mainly is there an economic justification for construction of a PSP in The mentioned area ? If the answer is positive then what capacity is an optimal choice,…?

Two types of assessment is carried out:
1. Dynamic assessment , 2. Static assessment .
In this paper only results of dynamic assessment is presented. Dynamic programming has many advantages over the enumeration scheme, the chief advantage being reduction in the dimensionality of the problem [1] .In dynamic assessment, PSP is evaluated accounting for total generating system . Then it is necessary to determine not only PSP and other candidate units parameters but also parameters of other units within the total generating system . On the other hand an accurate load forecasting for study period (20 years) must be done and necessary constraints as LOLP rate , fuel limitations(natural gas) for thermal units in cold season , limitations on dams seasonal energy , and so on also are taken in to consideration .

Three different categories of units are considered in this assessment : existing , under construction and finally candidate units .
Only candidate units based on optimal procedure will be selected (in type and quantity) by model , excluding RPSP that is unique in each case .

There is no other hydroelectric alternative candidate (Excluding RPSP) this is because these types of units are not selectable as unlimited numbers and existences of these units depend on topology of country and each one must be evaluated separately (like RPSP) .
Nine cases are generated for 9 steps of RPSP capacity (0,250,500,….,2000 Mw) it is because as a final assessment we need also to determine optimal RPSP capacity .

As mentioned before other selectable candidates are defined for model as below:

1. Steam Turbine 325Mw , 2. Base Gas Turbine 130Mw, 3. Peak Gas Turbine 130Mw , 4. Combined Cycle 400Mw .

2. Input Data Preparation

The dynamic modeling is performed by using WASP IV (Wien Automatic System Planning)[2], This model consists of six following main modules :

Loadsy – Fixsys -Varsys – Congen – Mersim - Dynpro (Dynamic Programming optimization)
In fact dynamic programming finally performed by last module and almost others act as input data preparation for this block .

In this section all necessary data , mathematical relations and a brief descriptions of calculation procedure is presented in short .

In first step based on the historical load data , peak load values are forecasted for the period of time under study.It is also assumed that Load Duration Curves (LDCs) have the same shape for similar seasons .

A sample of Normalized Load Duration Curve (NLDC) with 31 points for each season is shown in Table 1 . Model uses a fourier approximation for LDC to calculate necessary energy of system in each period .In next step data for fixed generating system consisting of existing , under construction and also for candidate units are determined .

Table .1 : Sample of NLDC points for
Year 2004 period 2: Summer (part of data)

NO	Load	Duration
1	1.0000	0.0000
2	0.9851	0.0077
3	0.9701	0.0158
١	١	١
١	١	١
١	١	١
26	0.6266	0.9181
27	0.6117	0.9410
28	0.5967	0.9594
29	0.5818	0.9747
30	0.5668	0.9881
31	0.5519	1.0000

Table .2
Sample of existing units main data

No	1
Power Plant Name	Tabs
Type	ST
Number of Units	2
MOL[Mw]	225
MGC[Mw]	300
Fuel Type	3
BLHR[kcal/kwh]	2235
AIHR[kcal/kwh]	2271
FOR[%]	17.1
SM[Days/Year]	59
FFC[C/million kcals]	546
FOMC[$/kw-month]	0.125
VOMC[$/Mwh]	0.213

The data depending on unit type have a wide variety , for example :

Power capacity , Fixed and variable operating and maintenance cost are determined based on Ref [3].

Force Outage Rate (FOR) is calculated based on Ref[4].

Base Load Heat Rate (BLHR) (or Heat rate at minimum operating level) for thermal units can be driven based on following formula:

$$BLHR = \frac{859.8}{e_1} \text{ [kcal/kwh]} \qquad (1)$$

And for Full Load Heat Rate (FLHR) we have :

$$FLHR = \frac{859.8}{e_2} \text{ [kcal/kwh]} \qquad (2)$$

Then Average Incremental Heat Rate (AIHR) can be calculated as below :

$$AIHR = \frac{FLHR * P_{full} - BLHR * P_{base}}{P_{full} - P_{base}} \qquad (3)$$

Where $e_1, e_2, P_{base}, P_{full}$ respectively are unit efficiencies and power capacities at minimum and maximum operating levels .

See Table.2 for existing and Table.3 for candidate units' data.

Table .3
Candidate units main data

No	1	2	3	4
Candidate Name	S325	G13P	G13B	CC40
Type	ST	GT	GT	CC
MOL[Mw]	163	0.1	65	200
MGC[Mw]	325	130	130	400
Fuel Type	3	4	4	4
BLHR[kcal/kwh]	2330	2507	3140	1857
AIHR[kcal/kwh]	2137	2507	1875	1583
FOR[%]	7.8	6.12	6.12	6.74
SM[Days /Year]	56	40	40	43
FFC[C/million kcals]	546	621	621	621
FOMC[$/kw-month]	0.3034	0.0892	0.0892	0.1392
VOMC[$/Mwh]	0.3935	0.8773	0.8773	0.6134
DCC:1.Domestic[$/Kw],	230.3	137.7	137.7	198.8
2.Foreign[$/Kw]	501.2	200.2	200.2	316.2
IDCC [%]	19.21	15	15	30
Plant Life[years]	30	15	15	30
CT[years]	5	2	2	4

Description	Fuel Type:
Heavy Fuel Oil(HFO)	1
Gas Oil	2
5+1	3
5+2	4
Natural Gas(NG)	5

following abbreviations are used :
Min Operating Level (MOL),Max Generating Capacity (MGC) , Force Outage Rate (FOR) , Scheduled Maintenance (SM) , Foreign Fuel Cost (FFC) , Fixed O&M Cost (FOMC) , Variable O&M Cost (VOMC) ,

Depreciable Capital Cost (DCC),Interest During Construction included in capital Cost (IDCC) Construction Time(CT) , Steam(ST),Gas Turbine(GT) , Combined Cycle (CC)

DCC is divided in two parts : 1. Domestic DCC, 2. Foreign DCC.

Transmission line losses and Transfer costs for RPSP also are included in model .

Inflow energy is determined for hydro plants as seasonally . An annual target for LOLP equal 1 day per year is selected . For RPSP we have also following exclusive parameters :

Cycle efficiency , Pumping capacity and Max feasible energy[5] that are given in Table .4 .

Table .4

RPSP Data (part of data)

MGC[Mw]	250	500	-----	1750	2000
FOMC[$/kw-month]	0.39	0.39	-----	0.39	0.39
Cycle Efficiency[%]	80	80	-----	80	80
Max.Feasible energy[Gwh]	137	237	-----	958	1095
Plant Life[Years]	50	50	-----	50	50
DCC: 1.Domestic[$/Kw]	229	237	-----	256	271
2.Foreign [$/Kw]	118	120	-----	127	134
CT[years]	4	4.5	-----	7	7.5

3. Dynamic Modeling

Basically this dynamic model is designed to find economically optimal expansion policy for an electric utility system within user specified constrains . Model searches for the optimal scheme by using the forward dynamic programming algorithms . When some of the configuration schemes have been ruled out as infeasible with respect to reliability indices , model search for the minimum cost path in the rest of the schemes from the planning start year to the level year . Suppose that there are 100 feasible configuration schemes in the final year of planning . Model finds the minimum cost in the 100 minimum cost paths . The searching process is shown in Fig .1 .
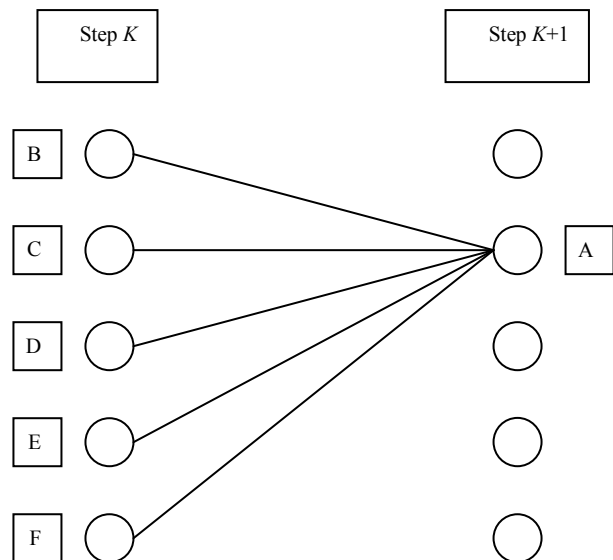

Fig.1 : Solution process of dynamic programming

Some of the feasible schemes in year K and year k+1 are shown in this figure . The cost of every scheme is determined by the minimum cost path from the beginning to the end of the planning year . when calculating the cost from the feasible scheme B in year k to the feasible scheme A in year k+1 , discount conversion should be made on the investment from B to A and the operational cost of A and add on to the cost of B . The same method is used for the other schemes C,D,E,F to A . Thus the minimum cost path to scheme A is found and retained while the other paths to A are waived since the other paths cannot form the optimal scheme according to the basic principles of dynamic programming . When the same principle is applied to all the feasible schemes in the year k+1 and the minimum cost path is found , the computation turns from the year k+1 to the year k+2 . The optimal planning scheme is then the one with the minimum cost in all feasible schemes' minimum cost paths in the final planning year [6] .

Model utilizes probabilistic estimation of system production costs, un served energy cost, and reliability, linear programming technique for determining optimal dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by some plants, and the dynamic method of optimization for comparing the costs of alternative system expansion policies.

The first step in apply the dynamic programming method is to define the cost objective criteria[7] . Each possible sequence of power units added to the system (expansion plan or expansion policy) meeting the constraints is evaluated by means of a cost function (the objective function) which is composed of :

Capital investment costs (I), Salvage value of investment costs (S), Fuel costs (F), Fuel inventory costs (L), Non-fuel operation and maintenance costs

(M), Cost of the energy not served (O) , The cost function to be evaluated by WASP can be represented by the following expression[2]:

$$B_j = \sum_{t=1}^{T} [\overline{I_{j,t}} - \overline{S_{j,t}} + \overline{F_{j,t}} + \overline{L_{j,t}} + \overline{M_{j,t}} + \overline{O_{j,t}}] \qquad (4)$$

Where:

Bj is the objective function attached to the expansion plan j, t is the time in years (1, 2, ... , T), T is the length of the study period (total number of years), and the bar over the symbols has the meaning of discounted values to a reference date at a given discount rate i. The optimal expansion plan is defined by: Minimum Bj among all j [2] .

4. Modeling Results and Conclusions

A dynamic method has been proposed which can be used to evaluate a PSP. Model is executed for 9 cases . This is because there are 9 steps for RPSP capacity . Results for case 8 (Capacity 1750 Mw) are given in Tables 5, 6 .

As shown in Table .5 , firstly (1+) means model is selected RPSP in first year of its availability (2011) and for achieving to a target LOLP (1 days per year = 0274%) in an optimal expansion planning many units from two other candidates also are selected (Peak Gas Turbine 13 and combined cycle 9 units in year 2011) and secondly (1+) defines that not only this type of candidate is an economic unit but also model try to select more than one unit but remember that PSP is Unique in each one of cases .
Two other candidates (Steam Turbine , Base Gas Turbine) are rejected by model .

In Table .6 cost main quantities are shown . Table.7 shows all cases Cumulative Costs for last year of study period (2023) .

A comparison has been made between the 9 mentioned cases .With attention to Table.7 and also Fig.2 it can be seen that without RPSP we have Maximum system Cumulative Cost and for capacity of 1750 Mw system Cumulative Cost will be at the lowest level . That means this is optimal capacity for RPSP .
A sensitivity analysis on RPSP economic justification with respect to its DCC shows that RPSP(1750 Mw) uneconomic behavior begins at DCC# 520 [$/Kw] .

Table .5
Final results for case8 (RPSP Capacity=1750Mw)
Part I

Year	LOLP %	ST 325 MW	Peak GT 130 MW	CC 400 MW	Base GT 130 MW	RPSP 1750 MW
2023	0.27	0	271	171	0	1+
2022	0.27	0	234	154	0	1+
2021	0.26	0	213	134	0	1+
2020	0.27	0	178	120	0	1+
2019	0.26	0	130	112	0	1+
2018	0.27	0	104	100	0	1+
2017	0.27	0	99	81	0	1+
2016	0.26	0	96	64	0	1+
2015	0.27	0	90	48	0	1+
2014	0.27	0	50	42	0	1+
2013	0.26	0	32	32	0	1+
2012	0.27	0	23	20	0	1+
2011	0.26	0	13	9	0	1+
2010	0.26	0	9	5	0	0
2009	0.11	0	0	0	0	0
2008	0.02	0	0	0	0	0
2007	0.01	0	0	0	0	0
2006	3.87	0	0	0	0	0
2005	6.73	0	0	0	0	0
2004	8.23	0	0	0	0	0

Table .6
Final results for case8 (RPSP Capacity =1750 Mw)
Part II

Year	Construction costs	Operating Costs	ENS Costs	Total Costs	Cumulative Costs
2023	838.4	1398.7	1.39	1487.0	43989.5
2022	906.9	1431.9	1.03	1607.2	42502.4
2021	874.8	1468.9	0.65	1719.6	40895.3
2020	817.5	1497.7	0.33	1809.8	39175.7
2019	865.2	1520.4	0.33	1894.9	37365.9
2018	1088.5	1554.9	0.66	2064.8	35470.9
2017	1052.6	1592.3	1.16	2141.8	33406.1
2016	1134.2	1635.3	1.75	2290.3	31264.3
2015	1049.1	1682.3	2.31	2415.6	28974.0
2014	1099.1	1694.3	2.43	2460.7	26558.4
2013	1216.0	1726.4	2.04	2593.9	24097.8
2012	1262.0	1753.4	1.21	2702.3	21503.8
2011	856.8	1781.7	1.03	2431.9	18801.6
2010	804.6	1807.8	1.45	2479.7	16369.7
2009	0.0	1838.3	0.73	1839.0	13890.0
2008	0.0	1938.5	0.23	1938.7	12051.0
2007	0.0	1972.7	0.14	1972.9	10112.3
2006	0.0	1964.0	321.41	2285.4	8139.4
2005	0.0	1952.0	809.03	2761.1	5854.0
2004	0.0	1986.4	1106.55	3093.0	3093.0

Cost unit : Million US $

As secondary results these conclusions can be found in model output : Total consumption energy, Load factor, Peak and minimum load, Annual system generated energy based of fuel types and also by Hydro units ,Expected costs of operation & maintenance and Energy Not Served (ENS) ,Capital cash flow summery of candidates .

Table .7
Cumulative System Costs for 9 steps of RPSP Capacity

RPSP Capacity [Mw]	Cumulative System Cost for Year 2023[MillionUS $]
0	44046.0
250	44031.6
500	44025.5
750	44007.8
1000	44005.9
1250	44003.4
1500	43991.9
1750	43989.5
2000	43995.7

Acknowledgments

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Biography

Alireza Sohrabi was born in Iran in 1966 , he received his B.Sc degree in Electrical Engineering (Power course) from The Tehran University Faculty of Engineering in 1989 . He joined Iran Ministry of Energy in 1991 , at present he is as production planning engineer in Tavanir Co (affiliated with Ministry of Energy) .
His areas of interest are Power System Planning and Reliability analysis .

Fig .2 .Total Cumulative System Costs