OPEN ACCESS
Saudi Journal of Engineering and Technology
Abbreviated Key Title: Saudi J Eng Technol
ISSN 2415-6272 (Print) |ISSN 2415-6264 (Online)
Scholars Middle East Publishers, Dubai, United Arab Emirates
Journal homepage: https://saudijournals.com

Original Research Article

Sustainable and Efficient Electricity Tariffs – A Case Study of Oman

Arif S. Malik[1*]

[1]Department of Electrical and Computer Engineering, Sultan Qaboos University, PO Box 33, Al-Khod 123, Oman

DOI: 10.36348/sjet.2022.v07i03.001 | **Received:** 22.01.2022 | **Accepted:** 28.03.2022 | **Published:** 04.03.2022

***Corresponding author:** Arif S. Malik
Department of Electrical and Computer Engineering, Sultan Qaboos University, PO Box 33, Al-Khod 123, Oman

Abstract

Price distortion caused by taxes, duties, or subsidies distorts the consumption of various goods and services. When prices become misleading they produce wastage and provide little or no incentive for conservation. Electricity tariffs are subsidized in Gulf countries due to socioeconomic and political reasons but with ongoing petrol prices and the Covid-19 situation, Oman is slowly moving toward removing subsidies. According to the economic theory of efficient pricing, the prices of goods should be set equal to their marginal cost of production. The purpose of this paper is to provide a methodology to estimate long-run marginal cost (LRMC) at the generation level using a traditional generation expansion planning software. The approach is then applied to find LRMC for Oman's Main Interconnected System (MIS). The LRMC at the level of generation busbar is then taken down to 132-kV, 33-kV, 11-kV, and 415-V. The LRMC calculation has shown that the power sector is highly subsidized.

Keywords: Electricity tariff; Energy planning; Long-run-marginal cost; Electricity pricing; Cost reflective tariffs; WASP-IV

Nomenclature

LRMC	Long-run marginal cost
WASP-IV	Wein Automatic System Planning Package; Version IV
MIS	Main Interconnected System
SRMC	Short-run marginal cost
IAEA	International Atomic Energy Agency
OETC	Oman Electricity Transmission Co.
MEDC	Muscat Electricity Distribution Co.
MZEC	Mazoon Electricity Co.
MJEC	Majan Electricity Co.
CRT	Cost Reflective Tariffs
MV	Medium voltage
LV	Low voltage
LOLE	Loss-of-load expectation index
LOLP	Loss-of-load probability
$LRMC_{Gen.Cap}$	Long-run marginal cost of generating capacity
$LRMC_{Busbar}$	Long-run marginal generation capacity cost at the generation busbar
O&M	Operation and maintenance
T&D	Transmission and distribution
NG	Natural gas
LDC	Load duration curve
GT	Gas turbine
RO	Rial Omani
Bz	Baiza; 1 RO = 1000 Bz
IBT	Increasing block tariff

Copyright © 2022 The Author(s): This is an open-access article distributed under the terms of the Creative Commons Attribution **4.0 International License (CC BY-NC 4.0)** which permits unrestricted use, distribution, and reproduction in any medium for non-commercial use provided the original author and source are credited.

I. INTRODUCTION

Over time the cost of production and demand for electricity continues to change, and that changes the price of electricity. Electricity prices differ not only from the time of year but also from geographical location, voltage level, etc. This makes it more complicated to fix electricity prices. However, when deciding electricity prices the social and political variables are of importance, which makes electricity prices even more complicated. The economic theory of efficient pricing demands that the price of products be equal to its marginal cost of production (Munasinghe 1989; Berrie 1992).

The marginal cost of electricity is the shift in the cost of opportunity that occurs when the amount produced increases by one kilowatt-hour, which is the cost of producing an additional unit of energy. The cost of further inputs required for the production of the next unit is intuitively a part of the marginal cost at each production stage. Marginal costs include all costs which vary from the levels of output at each production level and time period considered, while other expenses that do not shift with the output are presumed to be constant.

Marginal costs give consumers an idea of how much they would have to pay if, at a given time, they wanted to use one more electricity unit. The aim of marginal cost prices is to pass the cost of the supplier to the customer by time of use, geographic area, voltage level etc. In that trend, the user would try to change the level of consumption in order to reduce his bill for electricity. Tariffs based on marginal cost pricing would logically impact the increasing loads and ensure the power infrastructure's financial viability. There are two major marginal cost types: one is the long-run marginal cost (LRMC) and the other is the short - run marginal cost (SRMC) (Rothwell and Gomez 2003).

The LRMC is the amount it costs to produce a single new unit, given all production factors are variable. The SRMC is the amount it costs to produce one new unit, taking into account the capacity is set. In case of an optimal solution, SRMC is better than LRMC. The prices should maximize efficiency at each moment when SRMC is set, as SRMC represents the real incremental cost to the imposed group by using one more unit of output. There are many challenges in the practical implementation of using SRMC; one of them is that the prices set on the basis frequently vary significantly during the time the new capacity is added into the network. On the other hand, LRMC pricing should solve this problem considering the potential development program and reducing the cost over time (Malik and Al-Zubeidi 2006).

The LRMC tariff represents the target of the efficient allocation of resources (Munasinghe and Warford 1982). A significant consideration for estimating LRMC is the sum of future resources that consumer actions use or save (Malik and Al-Zubeidi 2006). The LRMC method involves not embracing the sunken costs associated with the current generation mix and formulating a mixture that results in the lowest expected cost of meeting demand given current technology, fuel prices, and load shapes (Synergy's Costs and Electricity Tariffs). There are two steps to the LRMC dependent electricity pricing mechanism. In the first stage strict long-run marginal costs will be calculated. In the second stage of developing a tariff based on LRMC, deviations from strict LRMCs are considered to meet important financial and other social, economic, and political criteria (Pacudan and Hamdan 2019). This second step of adjusting strict LRMC is generally as critical as the first stage measurement, particularly in Oman, where residential customers have traditionally received heavy subsidies.

Other pricing approaches include a cost accounting approach. It is a conventional method that relies on accounting data to develop a tariff structure. Pricing of accounting costs has drawbacks in controlling growth in peak demand throughout the day by providing a fixed cost of electricity (Munasinghe and Warford 1982). The resource is addressed as if it is as plentiful or scarce as it was in the past. The traditional accounting approach involves recovering sunk costs and is incompatible with the goal of efficient resource allocation (Synergy's Costs and Electricity Tariffs). Because of their retrospective approach, accounting cost pricing gives the wrong impression of resource costs.

This article explains the methodology adopted to estimate the LRMC at generatio level using a generation expansion planning software. WASP-IV is the framework used to calculate the LRMC at generation level (Wien Automatic System Planning Package, WASP-IV 2003). Developed initially for IAEA, WASP is freely distributed to utilities and non-profit organizations of IAEA member countries. As a case study Omani power sector is chosen to find the strict LRMC at the Generation Busbar level of Main Interconnected System (MIS). The MIS of Oman consists of eleven power generation plants owned and operated by separate companies; a transmission grid of 400/220/132 kV owned and operated by Oman Electricity Transmission Co. (OETC); and three distribution networks owned and operated by Muscat Electricity Distribution Co. (MEDC), Mazoon Electricity Co. (MZEC) and Majan Electricity Co. (MJEC). The data of generation and load forecasts are gained from (OPWP's 7-Year Statement (2018-2024) 2018). Typical values are used where detailed data were not available due to confidentiality/sensitivity, such as heat rates.

Until recently, power rates were calculated in Oman, based on an accounting approach. Such rates are based on the average cost of electricity production, transmission, and distribution. Such production costs consist of the expenses of depreciation and borrowing, operating and maintenance costs, wages and administrative costs, fuel costs, etc. Tariffs are then regulated for different sectors and heavily subsidized for the residential sector.

Oman introduced high-value customers' Cost Reflective Tariffs (CRT) in 2017. The new tariff is designed to better reflect the actual costs of providing electricity to large customers of government, commercial, and industrial sectors with an annual consumption exceeding 150 MWh. CRT structure reflects both electricity generation, transmission, distribution, and supply costs to customers. Under this tariff, the user must bear all costs of buying energy without government subsidy; since its inception, CRT has been revised each year. The latest CRT for the year 2020 can be assessed on the internet at [8]. The introduced CRT for high-value customers consists of four distinct components. The first is of energy charges at the electricity bulk supply tariff; the second is a transmission use of system charge; the third is a distribution use of system charge; the last component is a charge for the administration costs of supply.

The paper is divided into four sections. Section 2 introduces the general technique adopted for LRMC calculation using WASP-IV. Section 3 provides the load and generation data of MIS, Oman. Section 4 presents the results, and section 5 presents the conclusions and policy implications a few recommendations.

II. LRMC Methodology

In addition to investing in infrastructural elements such as transformers, medium voltage (MV) and low voltage (LV) cables, the cost of supplying additional energy in demand represents the fuel costs of generating electricity, operating and maintenance costs as well as the capital cost of expanded generation and transmission capability due to increased peak load. The LRMC has two main components–the marginal cost of power and the marginal cost of energy. The marginal cost of production is the cost of meeting the increased load that will be sustained indefinitely in the future. The marginal cost of power is the cost of generation, transmission and distribution capacity. The marginal cost of energy is related to the marginal cost of supplying extra kWh of energy, and that includes fuel cost and operation and maintenance variable cost.

A. *Marginal Generation Cost Calculation*

The marginal cost of generating capacity is calculated using the 'least-cost' capacity expansion plan and is expressed in$/kW-yr annually. A generation planning package named WASP-IV model is used as stated earlier for this analysis. WASP is one of the most extensively used and oldest tools for long-term capacity expansion planning. It was developed for the International Atomic Energy Agency (IAEA) and has subsequently been utilized for generation capacity planning in a variety of academic and development initiatives by over 100 countries, including all IAEA members and affiliate governments. The World Bank and other funding agencies regard it as a conventional technique for long-term GEP. It has been used to validate market models and has a lengthy track record of accuracy (Foley *et al*. 2010).

The model finds the most economical optimal generation expansion plan for an electricity-generating system over a period of research that could last up to 30 years. The best or optimal plan is calculated against the estimated discounted total costs. The model uses probabilistic estimates of production costs, energy costs not served, and reliability along with a dynamic optimization method to compare the costs of alternative system expansion policies.

In Equation (1), below is given the optimum generation expansion plan in the WASP-IV model defined by the minimum value of the objective function:

$$Minimize: \quad P_j = \sum_{j=1}^{J} \sum_{t=1}^{T} \left[\overline{CC}_{j,t} - \overline{SV}_{j,t} + \overline{FC}_{j,t} + \overline{MC}_{j,t} + \overline{UC}_{j,t} \right] \qquad (1)$$

Where,
CC = Capital construction costs of candidate units,
SV = Salvage value of candidate units beyond the study period,
FC = Fuel costs of power plants in the system,
MC = Operation and maintenance cost,
UC = Cost of unserved energy

The overbar on the symbols implies that all of these expenses are expressed in discounted costs. P is an objective function of the expansion plan j and t is time in years (1 to T), and T implies the duration of the study in years. It may be noted that the committed plants and the existing plants construction costs are not included in the objective function. These costs are considered sunk.

The following relation needs to be fulfilled:

$$[U_t] = [U_{t-1}] + [A_t] - [R_t] + [C_t] \qquad (2)$$

Where:
$[U_t]$ is an index containing the number of all generating units in service for a given expansion plan during year t
$[A_t]$ = Index of committed units' addition in year t,
$[R_t]$ = Index of committed units' retirements in year t,
$[C_t]$ = Index of candidate generating units added to the system in year t,

The additions and retirements of committed units in the study period are input data. The variable to be calculated is the undefined $[C_t]$; this variable is called a system configuration vector or simply a system configuration.

The configurations that are fit for simulation should meet the following constraint:

$$(1 + a_t)D_t \geq G(U_t) \geq (1 + b_t)D_t \qquad (3)$$

It simply states that the year t system's installed generation capacity $G(U_t)$ must be above the peak demand D_t, between the maximum and minimum reserve margins of the current year. Where a_t and b_t are the maximum and minimum reserve margins in percentage respectively.

In WASP, the reliability is assessed in terms of loss-of-load probability (LOLP), which represents the accumulated likelihood that the load will surpass the capacity of the system. A more useful loss-of-load expectation index (LOLE) may be calculated from LOLP, which is generally given in days/year. LOLE 's planning standard in Oman is 1 day per year. WASP assesses system configuration reliability with respect to the Loss-of-Load Probability Index (LOLP). For every cycle of the year, this index is calculated in WASP and the average yearly LOLP is the sum of the LOLP period divided by the time periods.

If $LOLP(U_t)$ is the annual LOLP, then every acceptable configuration that meet the reserve margin criteria (Eq. 3) must also satisfy the following constraint:

$$LOLP(U_t) \leq V_t \qquad (4)$$

Where V_t is the limit value that the user has given as input data.

The cost of marginal generation capacity includes: (a) incremental costs for capital; (b) incremental fixed operating and maintenance (O&M) cost; (c) incremental cost for unserved energy; and (d) fuel cost savings.

The method used for this study to assess the marginal cost of generation capacity has the following fundamental steps (Malik and Al-Zubeidi 2006):

- The optimum solution for the forecast of the reference load is calculated using the WASP-IV model. This is the base case.
- For all years, a constant load rise of 100 MW is applied to the annual peak load to find the incremental generation capacity addition. Load increment is considered to be at average load factor; thus, load duration curves are unchanged from the base case.
- With the increased loads, the generating system is re-optimized.
- A twenty-five years period is taken, and the long-run marginal (LRM) capacity cost measurements are carried out.
- The incremental components of the capital cost, O&M cost and unserved energy cost of the marginal capacity cost are determined by the following equations.

$$\Psi_A = \overline{CC_A} - \overline{SV_A} + \overline{MC_A} + \overline{UC_A} \qquad (5)$$

$$\Psi_B = \overline{CC_B} - \overline{SV_B} + \overline{MC_B} + \overline{UC_B} \qquad (6)$$

$$\Delta D_1 = \Psi_A - \Psi_B \qquad (7)$$

$$PWF = \frac{(1+i)^T - 1}{i(1+i)^T} \qquad (8)$$

$$CRF = \frac{1}{PWF} \qquad (9)$$

$$\Delta L = 100 \times PWF \qquad (10)$$

$$\alpha = \frac{\Delta D_1}{\Delta L} \times CRF \qquad (11)$$

Ψ_A in (5) is the sum of the present value of the capital cost minus salvage value, O&M cost, and unserved energy cost of the optimal base case. The subscript A is for the base case. Ψ_B in Equation (6) is the sum of the present value of the capital cost minus salvage value, O&M cost, and unserved energy cost of optimal incremental load case. The subscript B is for the incremental load case. ΔD_1 in (7) is the difference between the two cases. Equation (8) is the present worth factor (PWF), and (9) is the capital recovery factor (CRF); where i is the discount rate, and T is the number of years in the study period. ΔL in (10) is the present value of 100 MW load, which is added throughout the study period. The α in (11) is the annuitized value of incremental components of capital, O&M, and unserved energy costs of marginal capacity cost in \$/kW-yr.

- The incremental cost of the fuel-saving portion is calculated by making a separate simulation run, call it case C. The case C is made by using the optimal plan of capacity additions of the increased load case and the base-case load forecast. Note that case C is a simulation case and not an optimal case. The following set of equations are used to find the marginal cost of fuel-saving component.

$$\Delta D_2 = \overline{FC_A} - \overline{FC_C} \qquad (12)$$

$$\beta = \frac{\Delta D_2}{\Delta L} \times CRF \qquad (13)$$

The difference ΔD_2 of (12) is the present value of annual fuel costs $\overline{FC_A}$ of the optimal base case and the present value of the annual fuel costs of simulation case $\overline{FC_C}$. The β in (13) is the annuitized value of incremental components of fuel cost saving of marginal capacity cost in \$/kW-yr. In general, the fuel cost saving component β is negative.

- The marginal cost of generating capacity, $LRMC_{Gen.Cap}$, is obtained by adding the two components α and β.
  $$LRMC_{Gen.Cap} = \alpha + \beta \qquad (14)$$
- The $LRMC_{Gen.Cap}$ at the bus bar should be modified as follows for reserve margin and station losses:

$$LRMC_{Busbar} = \frac{LRMC_{Gen.Cap.}(1+RM\%)}{(1-L_{Station}\%)} \qquad (15)$$

Where $LRMC_{Busbar}$ is the long-run marginal generation capacity cost at the generation busbar after taking into account reserve margin, RM, in the system, and the average capacity loss at the power stations, $L_{station\%}$.

- The marginal cost of energy in $/kWh is here defined as the increase in variable cost (fuel plus variable O&M) divided by the increase in kWh resulting from a slight increase in demand over a given period of time. Remember that not all generating units currently in use at their maximum levels contribute to marginal energy costs, as combinations of frequent forced outages mean that any unit can be required to meet any portion of the increase in system loads. Thus the probability of each possible circumstance is weighted by its likelihood of occurrence and therefore the consequence is the expected value of the marginal cost of energy. The T&D energy losses at each voltage level contribute to the marginal energy cost at the consumer level. Since the generation energy mix in Oman is mainly combined cycle and gas turbine a simple approach is used to calculate the energy LRMC. The LRMC of peak energy is the operating cost of the marginal generating unit to be employed to meet the incremental peak of kWh. Fuel and variable (O&M) costs are included in the operating cost. In the same way, the off-peak energy LRMC, which refers to an increase in load over the off-peak period, would typically be the operating costs for the base load plant used during this duration.
- The calculation of transmission and distribution (T&D) capacity costs cannot be carried out using the least cost process, since the design of the transmission network is a function of the geographical distribution of capacity generation with respect to the load centers; the construction of the transmission network cannot follow an independent course. Since transmission and distribution companies are independent entities in Oman and have worked out their transmission and distribution capacity charge for CRT's identified customers that charge is considered as average incremental transmission and distribution cost. Average incremental Transmission & Distribution (T&D) cost added including incremental losses cost to get LRMC at 132kV, 33kV, 11kV and Distribution 415V level. The incremental losses are assumed at the time of peak. Since normally there is no data of peak losses, the following empirical equations are used to find the peak loss [4].

$$L_S = c\,(load\ factor) + (1-c)\,(load\ factor)^2 \qquad (16)$$

$$Peak\ Loss = \frac{Average\ Loss}{L_S} \qquad (17)$$

Where L_S is the loss factor, c is a constant and its value is taken 0.3 and 0.15 for transmission and distribution systems respectively.

The next section describes the MIS generation and load data of Oman used to apply the LRMC approach decribed above.

III. MIS Generation and Load Data

A. Generation Data

The planning of the generation expansion is carried out for the MIS between 2019 and 2043. The MIS system consists of several plants on either combustion turbines or combined cycle plants. The fixed or current system consists of a power of some 9000 MW [10]. The plants that are going to retired during the study period and those who are committed to coming within the first few years of the study period are also considered. Table 1 offers technical and economic data for fixed and committed plants in the system. The plants with zero number of sets in the table indicate the plants that are committed. The committed plants are added in energy simulation according to the year they are ready to operate. All power plants, except the last one, are powered by natural gas from domestic production with a fuel cost of $3/MMBtu or 1189 ¢/$10^6$ kcal used for WASP input. The last power plant is a committed Solar PV power plant with 500 MW capacities that will be added in 2022, and another 500 MW will be added in 2023. Solar PV is modeled as a thermal plant with a high forced outage rate of 62%, reflecting a capacity factor of 38%. Table 2 provides technical and economic data for candidate plants used for expansion. The third column of the table shows the fuel used for the first three plants, which is natural gas (NG). The fourth candidate is Solar PV, the fifth is Coal, and the last candidate is the wind in Duqm. The extra data needed for candidate plants beside the existing and committed plants include the capital cost, plant lifetime, and construction period.

Table-1: Summary description of thermal plants in the year 2019

No.	Plant Name	No. of Sets	Min. Load MW	Capacity MW	Heat Rates kcal/kWh Base Load	Heat Rates kcal/kWh Incr Load	Fast Spin Res %	FOR %	Sched. Maintenance Days	O&M (FIX) $/kW-month	O&M (VAR) $/MWh
1	ALMA	5	37	92	2580	2580	0	2	34	1.63	0.77
2	GHRU	4	43	96	2579	2579	0	5	37	2.07	1.15
3	GW18	4	8	18	4012	3154	9	8.8	27	3.4	0.17
4	GCC1	1	27	68	3287	2428	9	8.3	27	10.37	0.67
5	GCC2	1	28	67	3287	2428	9	8.3	27	10.37	0.67
6	GHMG	4	11	27	3639	2780	9	4	23	5.33	1.4
7	WJGA	10	12	31	3657	2798	9	5	31	2.76	0.16
8	RR83	6	42	83	3636	2777	9	5	37	1.37	2.14
9	BRK1	1	230	435	3389	2530	9	3	27	9.08	0.14
10	BRK2	1	365	688	3099	2240	9	3.2	27	7.77	1.1
11	BRK3	1	400	754	2747	1888	9	3	27	20.05	0.98
12	SHR1	1	316	597	3071	2212	9	3	27	5.84	1.2
13	SHR2	2	400	754	2747	1888	9	3	27	20.05	0.98
14	SURa	1	601	1134	2716	1857	9	3.2	27	13.01	1.96
15	SURb	1	459	866	2794	1935	9	3	27	13.01	1.1
16	IBRa	0	304	725	2765	1906	9	3	27	5.84	0.96
17	IBRb	0	304	725	2765	1906	9	3	27	5.84	0.96
18	SO3a	2	450	850	2740	1881	9	3	27	13.01	1.1
19	SOLR	0	100	100	0	0	0	62	10	1.95	0

Table-2: Summary description of candidate plants used for expansion

No.	Plant Name	Fuel	Min. Load MW	Capacity MW	Capital Cost ($/kW)	Plant life (yrs)	Construction time (yrs)	Heat Rates kcal/kWh Base Load	Heat Rates kcal/kWh Incr Load	Fast Spin Res %	FOR %	Sched. Maintenance Days	O&M (FIX) $/kW-month	O&M (VAR) $/MWh
1	OCGT	NG	100	100	1101	25	3	2520	2520	0	3	34	1.46	3.5
2	CCG1	NG	222	700	978	30	3	2522	1266	9	2.5	27	0.92	3.5
3	CCG2	NG	175	430	1104	30	3	2521	946	9	2.5	27	0.83	2.0
4	SOLR	PV	100	100	2671	25	2	0	0	0	62	10	1.95	0
5	COAL	Coal	200	600	3636	30	4	2219	2068	10	10	30	3.5	4.6
6	WDUQ	Wind	50	50	1877	25	3	0	0	0	70	10	3.3	0

B. Load Data

In WASP, the load model is of the load duration curve (LDC). The annual sequential hourly load curve of 2016 is used to render LDC for winter and summer seasons. Fig. 1 shows the normalized yearly LDC. The summer and winter LDCs are then normalized, and the shapes of LDCs are assumed the same for the whole study period. The peak load ratio of winter to summer is 0.8 from the actual data, and to complete the load data, annual peak loads are required for the study period. This is a compact way of giving load data for the study period. The annual peak load for the study period increases from 7358 MW to 23,707 MW, with an average load growth of about 5%. Also, the average annual load factor is equal to 61.26%. Fig. 2 shows the peak load from 2019 until 2043.

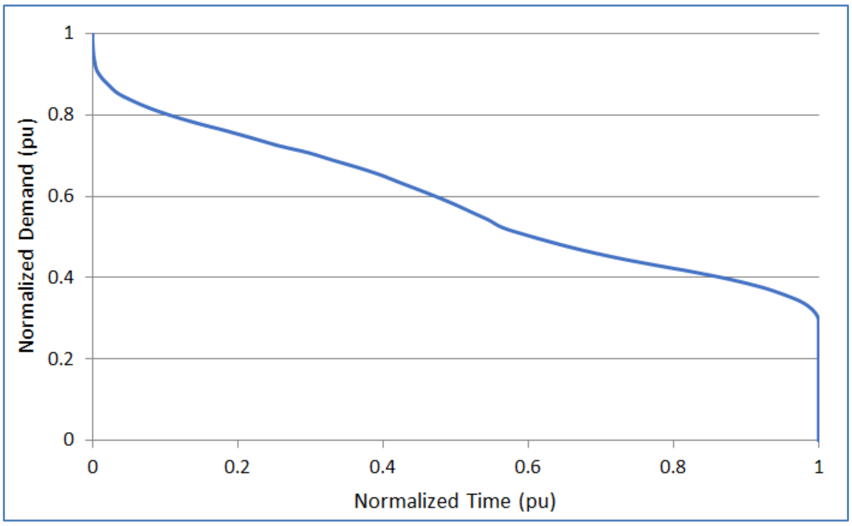

Fig-1: Normalized load duration curve of 2016

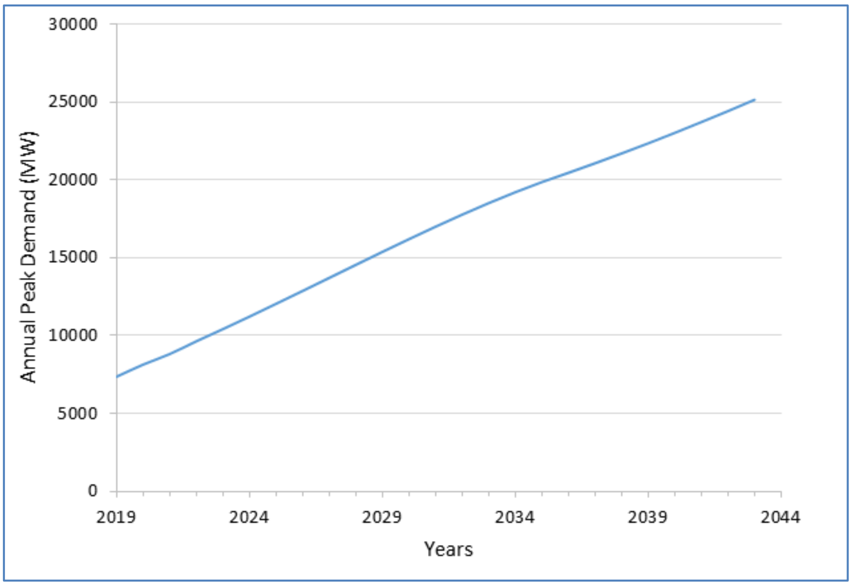

Fig-2: Annual peak demand from 2019 to 2043

C. Economic Data

Although WASP can include cost escalation of capital and fuel costs for the study period but the most important other data that is required to carry out the WASP study is the discount rate and the cost of unserved energy, as can be observed from the objective function. No escalation of fuel and capital costs are assumed. The discount rate used for the study is 8% and the energy not served cost as 3.2 $/kWh.

IV. RESULTS AND DISCUSSIONS

A. Marginal Generation Capacity Cost at Generation Busbar

The marginal capacity cost is acquired by following the procedure mentioned in the methodology section using equations (2)-(10) above. The estimated marginal capital cost, marginal fixed O&M cost, unserved energy cost, and the fuel cost saving over 25 years of planning period comes out to be $146.69/kW-year, $21.91/kW-year, $35.65/kW-year, and −$49.95/kW-year respectively. The fuel cost saving component, as expected, is negative (refer to the methodology section) because the added marginal capacity is fuel-efficient and has an advantage of fuel-saving. After adding all the components at the generation level, the total marginal capacity cost, is equal to $154.30/kW-year. The $LRMC_{Busbar}$ at the generation bus bar level using (12) assuming an average 8% reserve margins (corresponding to LOLE of 1 day/year) and peak generation capacity loss of 1.5% is $169.18/kW-yr.

B. Marginal Generation Energy Cost at Generation Busbar

The difference between generation energy cost at peak and generation energy cost at off-peak is due to the efficiency of the units between gas turbine and combined cycle gas turbine. Peaking units for MIS are gas turbines (GT) with an annual average efficiency of 30% assumed. There is a flat rate of gas fuel cost of

© 2022 |Published by Scholars Middle East Publishers, Dubai, United Arab Emirates

$3/MMBtu charged to power generation companies in Oman. The marginal energy cost of these GT units with 30% average efficiency is equal to 3.41 ¢/kWh. The O&M cost of Gas turbines is assumed as $3.5/MWh (EIA 2016) or 0.35 ¢/kWh. The total marginal energy cost, including O& M at the generation level, is then 3.76 ¢/kWh. After adjusting for 1.5% station usage, the marginal generation peak energy cost at the generation busbar level is 3.82 ¢/kWh.

Similarly, the off-peak units for MIS are combined cycle gas turbine with an annual average efficiency assumed as 50%. The marginal energy cost of these units at the generation level then worked out to be 2.05 ¢/kWh. The marginal off-peak energy cost at the generation busbar level after adding O&M cost of 3.5 $/MWh and adjusting for station use of the energy we get 2.44 ¢/kWh.

C. Marginal Cost at 132-kV, 33-kV, 11-kV and 415-V

Oman Electricity Transmission Company (OETC) is licensed to operate the main transmission network and Dhofar Power System. There is a charge for using the transmission network depending on the amount of load consumed by the customer during the annual system peak. The value of this transmission charge is 15,900 RO/MW-year (41.34 $/kW-year, 1 Rial Omani (RO) = 2.6 US dollars) for 2020 [8]. Note that this is the demand charge and can be distributed in monthly bills. The industrial complexes directly connected at 132-kV does not pay distribution cost. The distribution companies in Oman charge distribution cost of 4.0 RO/MWh, 5.0 RO/MWh, 9.0 RO/MWh at 33-kV, 11-kV, and 415-V, respectively [8]. It can be noted that the distribution cost is charged in energy rather than capacity. Table 3 provides the T&D system charges applied in Oman. The distribution energy charges are converted to capacity charge by assuming the load factor of 61.26% and 8760 hrs in a year. Table 4 shows the system components and average and peak losses. The peak losses have been calculated using (13) & (14). The important results are shown in tables 5, 6, and 7. Table 5 shows the long-run marginal capacity cost at generation busbar, 132 kV, 33-kV, 11-kV, and 415 levels. As the LRM capacity cost is moved from generation level to transmission and distribution level, the peak loss components are added in the cost. The LRM capacity cost of 132-kV transmission of $42.38/kW-year represents the transmission charge of $41.34/kW-year (table 3) plus the capacity loss due to losses at the peak time.

Table-3: T&D System charges applied in Oman

	T&D Charges	Annual Capacity Charge
Transmission charge	15,900 RO/MW-year	41.34 $/kW-year
Distribution charge 33kV	4 RO/MWh	55.81 $/kW-year
Distribution charge 11kV	1 RO/MWh	13.95 $/kW-year
Distribution charge LV network	4 RO/MWh	55.81 $/kW-year

Table-4: System components and the peak losses

System Components	Average Value	Peak loss
Generation auxiliaries	1.50%	1.50%
132-kV network	1.43%	3.20%
33-kV Circuit + Primary transformers	0.76%	1.85%
11-kV Circuit + Distribution transformers	2.86%	6.96%
LV network	1.11%	2.70%
Total	4.73%	11.51%

Table-5: Long-Run Marginal Capacity Cost at Generation Busbar, 132-kV, 33-kV, 11-kV and 415-V

Voltage level	Peak loss (%)	Generation ($/kW-year)	132 kV ($/kW-year)	33 kV ($/kW-year)	11 kV ($/kW-year)	415V ($/kW-year)	Total ($/kW-year)
Generation	-	154.30					154.30
Generation + 8% Reserve Margin	-	166.64					166.64
Generation busbar	1.50%	169.18	-	-	-	-	169.18
132 kV	3.20%	174.78	42.71	-	-	-	217.49
33 kV	1.85%	178.07	43.51	56.86	-	-	278.45
11 kV	6.96%	191.40	46.77	61.12	15.00	-	314.28
415V	2.70%	196.71	48.07	62.81	15.41	57.36	380.36

Table-6: Marginal Energy Cost at Generation Busbar, 132-kV, 33-kV, 11-kV, and 415-V

Voltage level	Average loss (%)	Peak loss (%)	Energy cost off-peak (c/kWh)	Energy cost peak (c/kWh)
Generation cost	-	-	2.40	3.76
Generation busbar	1.50%	1.50%	2.44	3.82
132 kV	1.43%	3.20%	2.47	3.94
33 kV	0.76%	1.85%	2.49	4.02
11 kV	2.86%	6.96%	2.56	4.32
415V	1.11%	2.70%	2.59	4.44

Table-7: LRMC at Generation Busbar, 132-kV, 33-kV, 11-kV, and 415-V

Voltage level	Capacity cost ($/kW-year)	Energy cost off-peak (c/kWh)	Energy cost peak (c/kWh)
Generation busbar	169.18	2.44	3.82
132 kV	217.49	2.47	3.94
33 kV	278.45	2.49	4.02
11 kV	314.28	2.56	4.32
415V	380.36	2.59	4.44

Similarly, the LRM of distribution capacity costs of 42.71 $/kW-year, 56.86 $/kW-year, 15.00 $/kW-year, and 57.36 $/kW-year are calculated from annual distribution capacity charge of table 3 and their corresponding peak losses. It may be noted that as these capacity costs are moved downstream, the prices are increased due to capacity loss components occurring because of losses. Table 6 shows the marginal energy cost both peak and off-peak at generation busbar, 132-kV, 33-kV, 11-kV, and 415-V. In the marginal energy cost at a peak, the peak losses are used to calculate the peak energy cost at 132-kV and other downstream levels. In contrast, off-peak marginal energy cost at 132-kV and downstream levels are calculated using corresponding average losses. Table 7 summarizes tables 5 and 6 showing LRMC at generation busbar, 132-kV, and 33-kV. 11-kV and 415-V.

The capacity costs must be recovered from peak customers because they burden the system and force the new investments. The seasonal tariffs for summer and winter can be derived from Tables 5 and 6. As MIS of Oman is a summer peaking system, the capacity cost can be recovered in summer, whereas in the winter season, the customers will pay the only energy cost. However, if an annual flat tariff is used to recover the marginal costs through energy charge only, then the capacity charge can be converted to energy charge using the annual load factor. Moreover, instead of peak and off-peak energy costs, a single flat energy cost can be recovered from a weighted average of peak and off-peak energy costs. From WASP results of optimization, the percentage of energy generated from the combined cycle as baseload plants with respect to the total energy generated is 98.2%. The energy generated by peaking plants (gas turbines) is only 1.8%. Table 8 shows the LRMC flat-rate tariff at each voltage level. Note that the energy cost is now the weighted average of peak and off-peak energy costs of table 7. It is worth noting that the LRMC flat-rate tariff of 9.71 ¢/kWh worked out at 415 V level is quite different from what the residential customers are charged in Oman. In Oman, the residential sector is charged with increasing block tariffs. The first block of 3000 kWh is charged 10 Bz/kWh (2.6 ¢/kWh, 1 US cent ≈ 3.85 Bz) and the last block tariff is for above 10,000 kWh consumption [12]. Even for the last block, which is applicable for above 10,000 kWh consumption per month, the charge is only 30 Bz/kWh (7.8 ¢/kWh). Likewise, commercial, industrial, governmental, agricultural, and other sectors are also subsidized.

Table-8: LRMC flat rate tariff at Generation Busbar, 132-kV, 33-kV, 11-kV, and 415-V

Voltage level	Capacity cost (c/kWh)	Energy cost (c/kWh)	Total cost (c/kWh)
Generation busbar	3.15	2.46	5.61
132 kV	4.05	2.50	6.55
33 kV	5.19	2.52	7.71
11 kV	5.86	2.60	8.45
415V	7.09	2.63	9.71

V. CONCLUSIONS AND POLICY IMPLICATIONS

The paper has described a methodology to estimate long-run marginal generation cost using WASP-IV – a traditional generation expansion planning software. This methodology is then applied to the main interconnected system of Oman. In this analysis, the marginal cost of the power supply for the MIS at generation busbar, 132-kV, 33-kV, 11-kV, and 415-V rates are measured. The total marginal capacity cost at the generation busbar level is 169.18 $/kW-year, and the marginal energy cost is 3.82 ¢/kWh. Such costs increase as we switch from the generation stage to the different voltage levels downstream. The flat-rate tariff based on long-run marginal cost worked out at 415-V level is 9.71 ¢/kWh, which is quite far from the subsidized rate of 2.6 ¢/kWh in the residential sector. The subsidized rate does not even cover the marginal energy cost at the busbar level.

The LRMC dependent tariffs ensure that the power sector is financially viable and economically efficient. In Oman, the existing residential increasing block tariff (IBT) structure is highly subsidized and leading to wastage of resources. Although the IBT structure reduces the peak energy consumption, however, since the overall tariff is subsidized, it does not prevent the use of electricity during peaking hours, thus forcing more capacity investments to meet reliability targets. The economy of Oman is passing through lean time due to low petroleum prices coupled with the Covid-19 situation. Therefore, this may not be the right time to introduce the marginal cost-based tariff or cost-reflective tariffs (CRT), but once the situation is improved Government should seriously contemplate introducing LRMC or CRT tariffs in other sectors, including the residential sector. Applying a seasonal time-of-use tariff would be helpful in reducing consumption during peak hours, thus reducing the stress on the system during peak hours and ensuring the power system's financial viability.

REFERENCES

- Berrie, T.W. (1992). Electricity economics and planning. vol 16. IET,
- Cowen, T., Parfit, D. (1992). Against the social discount rate. In: Laslett P, Fishkin JS (eds) Justice between age groups and generations. Yale University Press, New Haven, CT, 144-161
- EIA, U. (2016). Capital cost estimates for utility scale electricity generating plants. US Department of Energy, Energy Information Administration Parts on PHP and batteries http://www eia gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption pdf
- Foley, A.M., Ó Gallachóir, B.P., Hur, J., Baldick, R., McKeogh, E.J. (2010). A strategic review of electricity systems models. Energy 35 (12):4522-4530. doi:https://doi.org/10.1016/j.energy.2010.03.057
- Malik, A.S., Al-Zubeidi, S. (2006). Electricity tariffs based on long-run marginal costs for central grid system of Oman. Energy, *31*(12):1703-1714. doi:10.1016/j.energy.2005.11.010
- Munasinghe, M. (1989). Electric power economics. Butterworths,
- Munasinghe, M., Warford, J.J. (1982). Electricity pricing: theory and case studies. International Bank for Reconstruction and Development, Washington, DC (USA),
- OPWP's 7-Year Statement (2018-2024). (2018). Oman Power and Water Procurement Co. (SAOC),
- Pacudan, R., Hamdan, M. (2019). Electricity tariff reforms, welfare impacts, and energy poverty implications. Energy Policy, 132:332-343
- Parfit, D. (1983). Energy policy and the further future: the identity problem. In: MacLean D, Brown P (eds) Energy and the Future. Rowman and Littlefield, Totowa, NJ, 166-179
- Rothwell, G., Gomez., T. (2003). Electricity economics. IEEE series on power engineering
- Synergy's Costs and Electricity Tariffs. Economic Regulation Authority, Perth, Western Australia,
- Wien Automatic System Planning Package, WASP-IV. (2003). IAEA, Vienna