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Impact analysis of electricity pricing on the reliability of integrated Nepal power system

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Abstract

Time of Use of Electricity Pricing (TOU) strategy is adopted by many countries to reduce the peak load and minimize the cost of Electricity. In this research, the effect of the TOU tariff system on the reliability of the Integrated Nepal Power System (INPS) has been investigated. Implemented TOU is based on three time periods: Peak time, Flat time, and Valley time (PFV). The moving variable method is used to find the optimal PFV period in a day. Particle swarm optimization (PSO) is used to find optimal prices corresponding to the given periods, where two objective functions are converted to a single objective function. Prices are modeled with the demand response and a new load pattern of consumers after TOU has been obtained. Power plants of INPS are modeled into four states model and the Monte-Carlo simulation is used to find the generation adequacy indices like Loss of Load Probability (LOLP), Loss of Load Expected (LOLE), and Loss of Energy Expected (LOEE) before and after the implementation of the TOU. The risk level of INPS is reduced by 37% and peak load is reduced by 4.2% after the implementation of TOU. It is found that the reliability of INPS can be improved with the help of TOU.

1. Introduction

Time of Use of Electricity Pricing (TOU) is a tool of demand-side management. It helps to flatten the load curve and reduces the stress in the power system by shifting the load from Peak to Valley time. A properly designed TOU tariff system is beneficial to both - the utility, and the consumers; and increases the reliability of the system [1, 2]. Most of the powerhouses in Nepal are Run-Off-the-River (ROR) type with designed discharge exceedance of around 40 percent. Because of the seasonal variation in a generation, and the dynamic nature of the load, Nepal's power generation is insufficient for more than 60 % of the time in a year. It has resulted in huge power imports from India to fulfill the peak power demand [3]. After the end of load shedding in 2017, Nepal is striving towards the improvement of power system reliability and intends to reduce imports and increase revenue. Fixed TOU system has been adopted in Nepal for Industrial Consumers. Industrial consumers only make up 40% of the total consumers, so, implementing TOU only for that small part of the total load doesn't guarantee the peak load reduction and smoothening of the load curve. For other consumers, TOU is not implemented, instead, consumers are categorized in terms of the tariff; such tariffs cause leakages [4]. Developing proper fences to avoid leakages is both challenging, and costly. Various researchers have identified the economic advantages of TOU in specific electricity markets like Brazil [5], Switzerland [6], Taiwan [7] , and Australia, etc., and have proposed two times/three time-period tariffs. Three time-period-based TOU tariff and its impact on the reliability of power system in Roy Billiton Test System (RBTS) has been addressed in [8].

This paper presents a new TOU tariff system for INPS over the existing tariff and compares the reliability of the system with the new tariff. Tariff is based on three periods: Peak period, Flat period, and Valley period tariff. Four state model of probability was built to evaluate the reliability of INPS before and after the TOU with the help of Monte Carlo simulation (MCS).

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2. Optimal period and new load curve

The moving variables method is used to find the optimal PFV period. It assumes three variables: m1, m2, and m3 corresponding to the Peak period, Flat period, and Valley period between the intervals of [PL_{max},PL_{min}]. Let PLt (where t = 1, 2… 24) be the hourly load sequence for a day. PLmin denotes the minimum of the sequence and PLmax the maximum. The objective function is the Root Mean Square Distance (RMSD) between PL_j and m_j. Optimal period partitioning of the hourly load of a typical day can be obtained by minimizing the following expressions of root mean square distance between them, as shown by (1).

$$R = \sqrt{\frac{1}{24}\sum_{t=1}^{24} PL_t - \sum_{i=1}^{3} O_{ij} M_{ij} P_L \in G_i} \tag{1}$$

Where $j = 1, 2,$ and 3 represent the Peak period, Flat period, and Valley period respectively; and G_j is the load set of the j-th period. If P_{Lt} is the element of G_j, $O_j = 1$, otherwise $O_j = 0$. The set of G_j which has the minimum root mean square distance represents the optimal Peak period, Flat period, and Valley period.

When electricity prices changes, there is the movement of consumer between low price time and higher price time. The price elasticity of the Demand Matrix is used to describe the shift of electricity demand among the periods [9] The new consumption pattern by the movement of consumers from lower price to a higher price after the TOU can be found from an apportionment technique and is given as:

$$L_i^{\text{before}} = L_i^{\text{before}} \left(1 + \frac{\Delta E_m}{E_M}\right) \tag{2}$$

E_m is the consumption of electricity in the m-th period before considering Time-of-Use (TOU), L_i^{before} is the load before TOU in the i-th hour of a day, ΔE_m is the change in electricity consumption in the m-th period after TOU, and m represents different periods such that $m \in \{p, f, v\}$.

3. Optimal prices and reliability

Optimal prices for Peak Flat and valley period are obtained with the help of Particle swarm optimization (PSO). Following are the objective function and constraints used in the optimization process.

3.1. Objective function and constraints

Two objective functions are considered for the optimization[10] and they are:

- Minimization of peak period power

$$F_{f1} = \min\{P_{Lt}^{\max}\ |_{t(1<t<24)}\} \tag{3}$$

- Minimization of difference between peak and valley power difference

$$\begin{aligned} F_{f2} = \min\{P_{Lt}^{\max}\ |_{t(1<t<24)}\} \\ - \min\{P_{Lt}^{\max}\ |_{t(1<t<24)}\} \end{aligned} \tag{4}$$

Here, $p = (p_1, p_2, p_3)$ are the prices of peak, flat, and valley, respectively and constraints are:[11]

- The Customer Benefit Constraint

$$g_1(p) = B(p_o) - B(p) \geq 0 \tag{5}$$

Where $B(p_0)$ and $B(p)$ represent the electricity paid by the customers before and after the Time-of-Use (TOU), respectively.

- The benefit of power supplier The total benefit of the power supplier is not reduced after TOU. i.e.

$$g_2(p) = B(p) - (1 - \delta)B(p_0) \geq 0 \tag{6}$$

Where δ be the benefit coefficient.

- Electricity Rate and constraint of valley period

$$\begin{aligned} g_3(p) &= p_1 - p_2 > 0 \\ g_4(p) &= p_2 - p_3 > 0 \\ g_5(p) &= p_3 - p_c > 0 \end{aligned} \tag{7}$$

p_c is the marginal cost per unit of energy for the utility.

- Load Inversion Constraint

$$P_{\text{pmin}} - P_{\text{vmax}} > 0 \tag{8}$$

3.2. Optimal prices for peak Flat and valley period

Two objective functions are converted to the single objective functions as:

$$F(p) = \alpha F_{f1}(p) + \beta F_{f2}(p) + J(p) \tag{9}$$

Where α and β are the ratio coefficients of $F_{f1}(p)$ and $F_{f2}(p)$. The penalty function $J(p)$ can be represented as $J(p) = \phi(k) \times H(p)$ [12]. The PSO algorithm is used to optimize the optimal peak, flat, and valley period prices. The generalized flow chart to calculate the optimal prices using the PSO algorithm is represented in Fig.1.

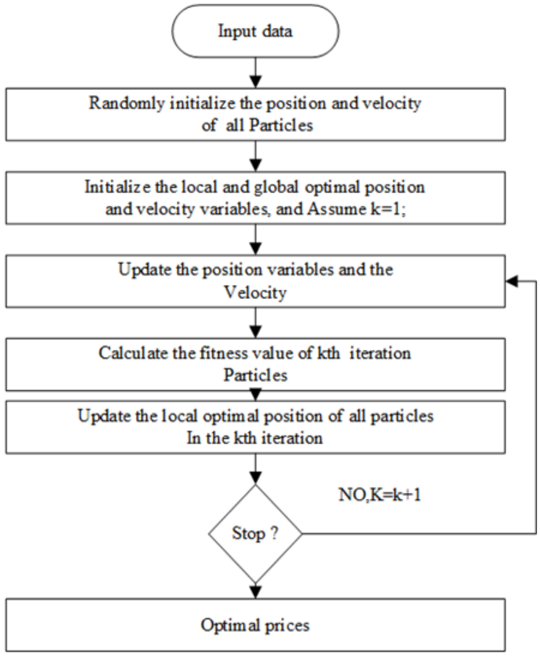

Figure 1: Flow chart of PSO to find Optimal Prices

4. Reliability evaluation

Monte-Carlo simulation method is used to evaluate the power system reliability. Four states model of the power plant is built with the help of the recursive method Full Capacity, 67% of the Full Capacity, 33% of the Full Capacity, and Zero Power Available State for accuracy. Uniformly distributed Random number is generated between range [0 1] and it is compared as follows[13]:

If U1<P(down), the unit is deemed to be in a totally downstate
If P(down)<U1<[P(down)+P(derated)], the unit is assumed to be in the de-rated state;
Else, the unit is UP and the total cumulative capacity available in the given simulation is calculated.
The cumulative capacity is compared with the hourly load of the year and reliability indices like LOLE, LOLP, and LOLE were calculated.

5. Test system

The methodology described in the previous section is implemented in INPS. The annual peak load of Nepal was 1408 MW on August 22 2018 at 7.05 PM. There are a total of ninety-one (91) generators present in INPS contributing 1156 MW of power. Power plants with less than a 1 MW rating have a total contribution of 12 MW in the system. The power that can be imported from India is 750 MW. Powerhouse trip data is collected to evaluate the four states model of probability. Six powerhouses have been taken as reference, and their four states model is built with the help of the recursive method The four-state model of remaining powerhouses is considered as the average of evaluated powerhouses. According to the annual report published by Nepal Electricity Authority (NEA), the marginal cost for utility is NPR 9 per unit including demand charge, and the average flat-rate tariff price before TOUP is NPR 11 [14] The Self-elasticity and cross-elasticity matrix coefficient used in this paper can be found in [15].

6. Case study

6.1. Period partitioning

Based on the moving variables method, the optimal Peak period, Flat period, and Valley period partitioning of the hourly sequential load has been obtained. Fig. 2 shows the peak that occurred in INPS from 7 pm to 9 pm in April. INPS followed the same pattern in May, June, July, August, September, October, and late March. Fig.2 represents the period partition of April.

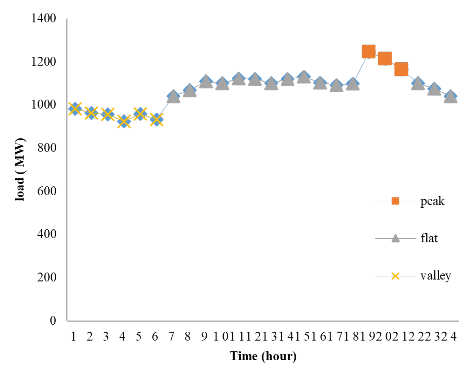

Figure 2: Period Partition of April, 22

From Fig. 3, it can be said that during winter, the peak period occurred in the morning from 7 am to 9 am, and in the night from 7 pm to 9 pm. Early March, February, November, December, and January have almost the same pattern as observed in December.

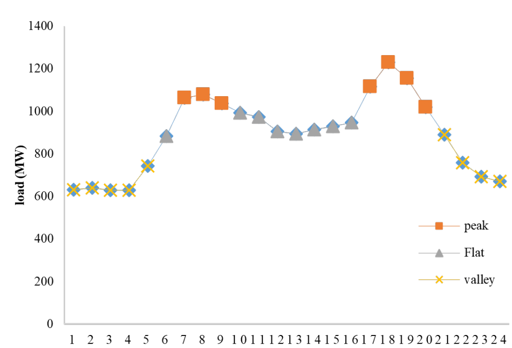

Figure 3: Period Partition of December, 22

6.2. Optimal prices for the PFV period

Optimal prices for 12 months are calculated by taking a reference of monthly peak load for each month. Optimal prices are given in Table 1. The peak price is higher than the previous price, and the Valley period price is lower than the previous Flat price. The maximum peak price calculated is NPR 16.97 for December because of the larger difference in Peak period power, and Valley period power.

Table 1: Optimal peak flat valley prices

Month	Peak Period	Flat Period	Valley Period
Apr 15 to May 14	14.29886	12.00604	9.800439
May 15 to Jun 15	14.84264	10.97393	10.35192
Jun 16 to Jul 16	14.05584	11.81112	9.068148
Jul 17 to Aug 17	13.30186	11.23712	9.906389
Aug 18 to Sep 17	13.22546	11.15368	10.04887
Sep 17 to Oct 17	14.20161	10.50438	10.06721
Oct 18 to Nov 16	14.57746	11.60086	9.826976
Nov 17 to Dec 16	13.30186	11.23712	9.906389
Dec 17 to Jan 14	13.93853	11.6224	9.296857
Jan 15 to Feb 14	14.20161	10.50438	10.06721
Feb 15 to Mar 13	14.57746	11.60086	9.826976
Mar 13 to Apr 14	16.97902	11.17794	10.04616

7. Daily Load Variation After TOU

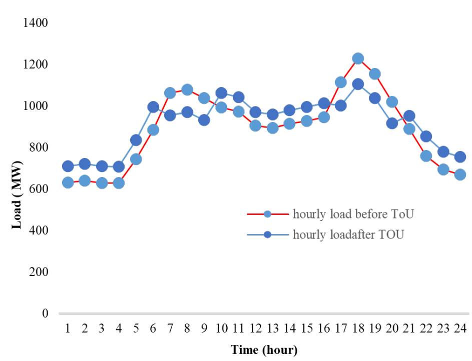

Figure 4: Load curve after TOU for December, 22

Fig .4 and Fig .5 represent the load curve after TOU for December 22 and April 22. It is found that by implementing the TOU, the peak load is reduced. The decrease in energy consumption due to reduction of the peak is shifted from peak period to flat and valley period. On December 22 daily peak load before TOU is 1230 MW and it is reduced to 1105 MW after TOU. Similarly, the daily peak of August 22 is 1246 MW before TOU and it is reduced to 1151 MW after TOU

Fig. 6 represents the load curve August 22 after TOU.

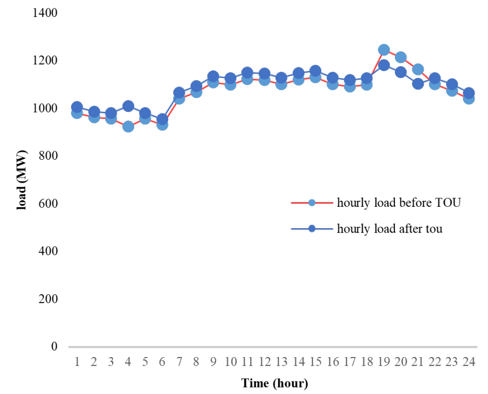

Figure 5: Load curve after TOU for April, 22

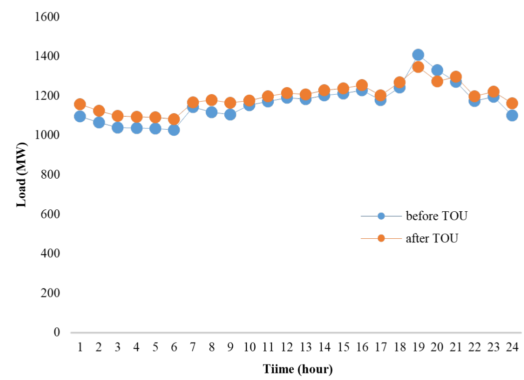

Figure 6: load curve of August 22 after TOU

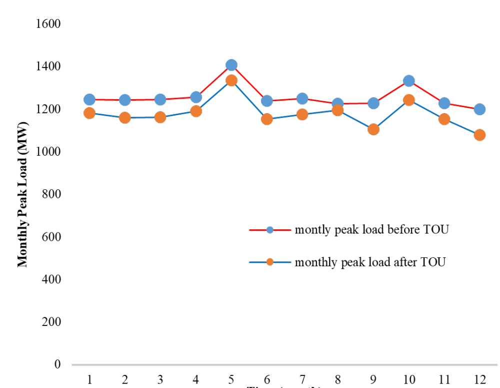

Figure 7: Monthly peak load variation after TOU

The annual peak load of 1408 MW occurred on this day. After the implementation of TOU the annual peak load is reduced to 1348 MW.

Similarly, a new load pattern for each day of the year was calculated. Monthly peak load variation after the TOU throughout the year is shown in Fig. 7. Daily Peak load after TOU is given in Table 2.

Table 2: PEAK LOAD VARIATION AFTER TOU

Daily peak load After TOU (MW)											
Apr/ May	**May/ Jun**	**Jun/ Jul**	**Jul/ Aug**	**Aug/ Sep**	**Sep/ Oct**	**Oct/ Nov**	**Nov/ Dec**	**Dec/ Jan**	**Jan/ Feb**	**Feb/ Mar**	**Mar/ Apr**
922	1061	1198	1114	1107	1203	1251	1211	1092	1088	1228	1047
1092	1128	1180	1212	1204	1204	1221	1220	1154	1170	1189	1098
956	1163	1189	1152	1197	964	1146	1098	1140	1181	1118	1200
982	1126	1241	1109	1239	1193	1196	1196	1162	1130	1192	1138
1060	1210	1247	1207	1301	1234	1201	1191	1098	1253	1150	1153
1012	1183	1237	1175	1253	1209	1228	1159	1168	1267	1166	1162
1049	1187	1048	1158	1306	1189	1153	1161	1074	1302	1165	1134
1072	1161	1141	1057	1198	1190	1186	1179	1170	1333	1168	1031
1012	1128	1201	1151	1206	1241	1122	1143	1177	1330	1086	1050
1108	1081	1187	1127	1296	1173	1110	1101	1174	1332	1053	1054
1139	1070	1144	1142	1300	1141	1087	1167	1230	1206	1162	945
1103	1178	1185	1193	1339	1146	1097	1132	1107	1306	1173	951
1133	1204	1211	1177	1263	1054	1029	1150	1208	1297	1086	981
1066	1226	1169	1205	1343	1066	1090	1136	1082	1285	1168	945
1193	1165	1230	1207	1345	1160	1161	1170	1147	1239	1125	1101
1114	1095	1214	1195	1319	1201	1106	1167	1174	1245	1134	415
1183	1210	1183	1196	1314	1196	1037	1083	1145	1229	1084	912
919	1055	1245	1153	1239	1186	1083	1146	1208	1164	1130	153
1186	1023	1219	1247	1314	1136	1089	1159	1177	1255	1139	302
1085	1134	1224	1258	1348	1079	1146	1168	1171	1264	1131	956
1015	1244	1111	1189	1306	1000	1168	1160	1129	1240	1127	932
1176	1245	1084	1228	1296	986	1180	1211	1199	1257	1138	936
1192	1128	1096	1190	1252	851	1145	1184	1148	1291	1076	360
1221	1095	1013	1198	1328	979	1103	1145	1177	1274	1089	1000
1231	1099	1079	1220	1408	1056	1174	1206	1162	1174	1097	970
1223	1108	955	1221	1324	1069	1160	1224	1208	1214	977	969
1247	1093	816	1207	1316	1079	1172	1226	1156	1241	940	945
1219	1163	803	1231	1298	1102	1181	1164	1119	1272	1012	1005
1153	1161	1019	1130	1293	1160	1171	1178	1151	1291	1116	980
1154	1229	989	1180	1210	1002	1220	1104	-	-	1075	967
994	1226	1104	1230	1316	-	-	-	-	-	-	-
-	1221	-	1208	-	-	-	-	-	-	-	-

7.1. Reliability evaluation

Most of the power plants of INPS are run off river type with designed discharge around 40%. So, power plants are modeled with two de-rated states of 67% of the Full capacity, and 33% of the Full capacity including Up and Downstate. Table 3 represents the four states model of the probability of the major six power plants of INPS. State 1 represents Full capacity state, State 2 represents 67 % of Full capacity state, State 3 represents 33% of Full capacity state, and State 4 represents Zero output state. Six major power plants have taken, and the average is taken for remaining power plants. According to the report of Power Grid of India 2018/2019, transmission line availability is 0.9982. Availability of power import from India is assumed to be equal to transmission line availability. Monte-Carlo simulation has been used to find the reliability indices before and after the TOU with a non-chronological load curve, as shown in Table 4.

8. Conclusion And Discussion

In this paper, TOU based on three time periods has been implemented in INPS. Annual peak demand of INPS reduced to 1335 MW from 1408 MW, risk in the system reduced to 0.000525 from 0.000827, energy not served to the consumer reduced to 530 MWhr/Yr from 1338 MWhr/Yr, and expected outage in an hour per year reduced to 4.59hr from 7.24hr after the TOU is Implemented. This indicates that we can improve the reliability of INPS by implementing TOU without

Table 3: FOUR STATE MODEL OF POWER PLANT

Four States Probability of Power Plant				
Power Plant	**State 1**	**State 2**	**State 3**	**State 4**
U. Marshy angdi	0.619	0.2688	0.0995	0.0127
Chilime	0.5427	0.2426	0.1928	0.0219
Khimiti	0.4695	0.3354	0.1918	0.0033
Kali gandaki	0.4523	0.2919	0.2557	0.0331
M. Marshy angdi	0.5199	0.3233	0.1423	0.0144
L. Marshy angdi	0.5301	0.2865	0.135	0.0484
Average	**0.5223**	**0.2914**	**0.1695**	**0.0223**

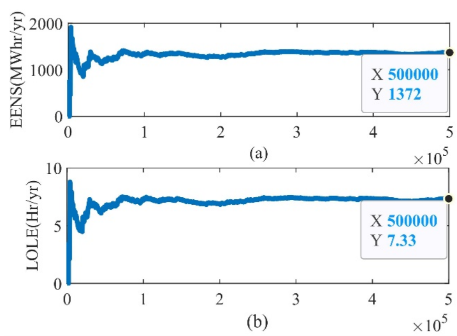

Figure 8: (a) EENS, (b) LOLE of INPS before TOU from MCS

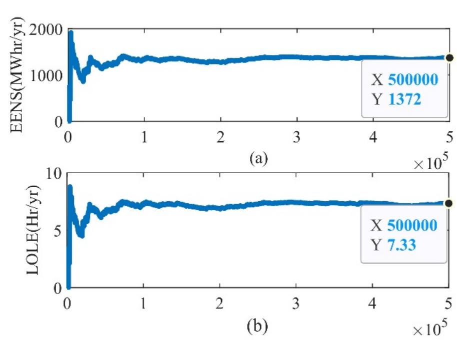

Figure 9: (a) EENS, (b) LOLE of INPS after TOU from MCS

Table 4: RELIABILITY OF INPS

Generation Adequacy Indices of INPS			
Description	**LOLP**	**LOLE (Hr/yr)**	**EENS (MWhr/yr)**
Before TOU	0.000827	7.33	1372.057
After TOU	0.000525	4.678	539.8
% change	-37	-37	-60

reducing the benefit to consumers and the utility.

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