Pros and Cons of Capacity Mechanisms- Real Case: Capacity Payment in IREMA

Iman Rahmati[1,*], Mazaher Hajibashi[2] and Seyyed Meisam Ezzati[3]

Abstract— **Energy-only electricity markets and energy+capacity markets have both been experienced in the real world, and each has advantages and shortcomings. Still, there are lots of arguments supporting each of the two designs. Furthermore, the energy+capacity market has different known forms itself, and several capacity mechanisms have been introduced in the literature and most of them have been tried in the real world. It is evident that the electricity market design in each country is customized to fit its socio-economic aspects. The main purpose of this paper is to look closely at Iran Electricity Market (IREMA) and assess the pros and cons of its main design in using the capacity mechanism. To this end, the history of IREMA evolution and the specific design of the capacity mechanism in this market is meticulously surveyed. The theoretical and practical principles that led IREMA founders to choose the EnCa mechanism are discussed. Also, positive/negative impacts of the capacity mechanism are analyzed.**

Index Terms— **Capacity Mechanism, Electricity Market, Energy-only market, Capacity Payment.**

I. INTRODUCTION

MORE than 3 decades has been passed since the first attempts toward restructuring the power systems. Since then, various designs for electricity markets have been theorized and implemented. Among all the classifications, from the viewpoint of a tradable commodity, electricity markets can be categorized into Energy-only markets and Energy+Capacity markets (EnCa markets). In short, in an energy-only design, producers only have income from the market when they produce energy, and their revenue is proportional to their generated energy level. In contrast, the EnCa market provides another source of revenue for generation companies. As well as the energy revenue, they receive money from the market if their generation facilities are available for a certain period throughout the year [1, 2].

Supply adequacy in the short-term (day-to-day planning) and long-term (over-yearly planning) is a major concern in power systems. By definition, supply adequacy means “The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements” [3]. Energy-only market design is known as the simplest design for the electricity market. However, electrical energy has special characteristics which bring about some concerns, at least about the supply-side adequacy in both the short-term and long-term, and capacity mechanisms are supposed to address these concerns. These characteristics are discussed briefly as follows:

A.1. Importance

Electrical energy is widely used in every aspect of human life, and not only the economic activities, e.g., industries, trade centers, etc., our health, security, and social order depend on it more than ever.

A.2. Unreplaceable

Although the transformation of other energy carriers to electrical energy is well known, none of them can replace electrical energy in most cases.

A.3. Inelastic demand

A location-based analysis by National Renewable Energy Laboratory (NREL) in 2006 concludes that the price elasticity of electricity consumption is very small. This report states that this inelasticity has remained almost unchanged for 20 years [4]. Another study in 2017 confirms that, specifically in the short-run, electricity demand is relatively inelastic [5].

A4. Not storable on large scale

Large-scale storage of electrical energy has been a historical challenge for power system operators except for some special cases (Large hydro dams,) and there has been no economic solution. However, recent progress in electrochemical batteries looks very promising, and in some power systems, a noticeable amount of battery storage is already installed.

All four factors mentioned above form the security of electricity supply as a high-level necessity, especially in power systems with a narrow reserve capacity margin and a high demand growth rate.

The electricity market is supposed to produce a clear message and enough incentive for investors to participate in generation expansion. However, there are many arguments supporting the idea that a pure energy market with marginal pricing can neither produce a clear message nor an efficient incentive for sufficient investment in generation capacity. Some key factors for this argument are:

Electricity is important, and unlike most commodities, all governments worldwide are very sensitive to its price. Based on economic theories, the energy-only market relies on temporary energy price spikes to attract investors [6]. For political reasons,

1-Electricity Market Dept., Iran Grid Management Company (IGMC), Tehran, Iran.
2-Electricity Market Dept., Iran Grid Management Company (IGMC), Tehran, Iran
3-Electricity Market Dept., Iran Grid Management Company (IGMC), Tehran, Iran
Corresponding author: rahmati@igmc.ir

most governments usually do not tolerate price spikes [7]. If the price caps set by regulators are too low to prevent price spikes, revenue inadequacy or a "Missing money" problem may arise, and the market fails to attract merchant investors for constructing new generation capacities [6-9].

Other than low price caps, some other reasons make energy-only markets end up in missing money problems, such as demand-side malfunction in the market, out-of-market actions by the system operator, and reliability criteria incontinence with customers' willingness to pay. Most electricity markets suffer from insufficient price elasticity because without real-time meters and billing for end-users; they wouldn't be able to respond to the real-time prices effectively [10]. This lack of demand-side participation makes the system vulnerable to high price spikes. This encourages the regulators to put lower price caps to reduce the consumers' risk, which can result in gross underinvestment in the generation sector [11]. Moreover, system operators take conservative measures to forestall the capacity scarcity condition in the market. By doing that, they prevent the formation of acceptable price spikes, leading to lower income for the generation sector [8].

In addition, subsidized expansion of renewable generations with low marginal costs exacerbates the missing money problem [8, 12, 13]. That's why capacity markets in many jurisdictions are already established and have been successful in encouraging investment in generation expansion [14].

Besides the missing money problem, the boom-bust cycle is a known problem in generation expansion. Construction of new generation facilities takes time, and since the stranded cost in the electricity sector is high [15], generally, there is a time delay between the occurrence of price spikes in the energy market and the entrance of new generation capacity. Generally, this phenomenon leads to boom-bust cycling in generation investment, which reduces the market performance [2]. The positive effects of capacity mechanisms in overcoming the boom-bust cycles are already well addressed in the literature. Compared to energy-only markets, EnCa markets experience boom-bust cycling over a longer period and with smaller amplitude [12, 16-19].

II. TYPES OF CAPACITY MECHANISMS

The main rationale behind EnCa markets is to produce a more stable revenue stream for the investors in the generation sector to reduce or eliminate the necessity of price spikes for the remuneration of the investment fixed costs. This way, the regulators' intervention to suppress the energy price during the scarcity condition wouldn't make a missing money problem. On the other hand, it is believed that compared to the dependency on casual price spikes, a more predictable revenue stream is more effectively aligned to the long-term adequacy concerns [10, 12].

It's worth stating that Capacity Market is one of the possible forms of Capacity Remuneration Mechanisms (CRMs) to be incorporated within EnCA markets. Indeed, some other tools have been proposed and implemented to address the missing money problem. The most known forms of the capacity mechanisms are as follows:

In general, the capacity mechanisms are categorized as Price-based and volume (quantity) based, and each may include Market-wide and need-oriented mechanisms.

In price-based capacity mechanisms, the price is known and paid to all or part of the generation capacity. While in the case of volume-based mechanisms, the amount of capacity which receives capacity revenue is predetermined.

In a market-wide approach, all the capacity is eligible to participate in the designated mechanism. However, in need-oriented mechanisms, some factors like technology, new investments, annual generation ratio, etc., determine whether or not the power plant receives this type of revenue. Figure 1 depicts the general categorization of capacity mechanisms.

The simplest form of Capacity Mechanism is Market-wide Capacity Payment, categorized as a Price-Based, Market-wide payment to all. Using Capacity Payment, all the generation capacity within the system is eligible to receive capacity revenue [12, 20].

The primary advantage of Capacity Payment is that it is very consistent with the price cap set, and it is tranquil to implement. Although capacity payment is mainly dedicated to assuring long-term supply adequacy, some adjustments, such as non-uniform payments, can be used to address the short-term adequacy concern. However, since a trivial change in the payment shifts the generation capacity largely, calculating the optimum level of payment is very difficult [2].

In the case of the Capacity Market, the regulator determines the targeted capacity level one to five years in advance. Then a competitive environment is formed, and the system operator pays the competition's winners. By design, Capacity Market is dedicated to long-term adequacy concerns. Contrary to Capacity Payment, a Forward Capacity Market (FCM) does not require an administrative price setting.

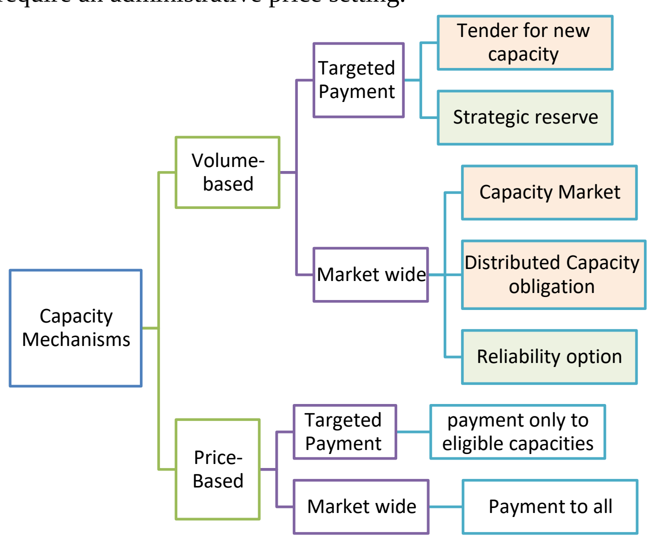

Fig. 1. Different types of capacity mechanisms

Instead of administrative price, the target capacity level should be determined for a forward capacity market, which is much easier and can be done based on the accepted operative standard and procedures. In practice, regulators and market operators prefer to use a sloped demand curve instead of a robust capacity requirement to mitigate the market power potential in the Capacity market [14].

The reliability option is another capacity mechanism similar to the Capacity Market, which is a kind of central buyer approach in which the system operator acts as the sole buyer [12, 20]. In the Reliability Option, the system operator buys the call option from the capacity providers. In case of scarcity or price spikes in the energy market, the system operator is cleared to use the right to call the capacities into service with the option strike price. In other words, the strike price would be an effective cap for energy prices [2]. Hence, it is evident that the Reliability Option is meant to regulate the market and handle the short-term capacity deficiency. The complexity of the Reliability Option is higher because both the strike prices and the amount of contracted option should be determined centrally. Central Buyer mechanisms such as Reliability Options and Capacity Market can mitigate market power in the energy market [12].

Capacity Obligation is very much similar to Capacity Market, and the desired margin between annual peak demand and available capacity is decided by a central authority [2]. But in this method, instead of the system operator, load supplier entities sign individual contracts with capacity providers [12, 21]. Capacity Obligation is a distributed mechanism to procure generation capacity, and from this perspective, it has the same attributes as a Central Forward Capacity Market and mainly addresses the long-term adequacy concern. However, since multi-sellers and multi-buyers are active in Capacity Obligation, a higher competition level is expected. The revenue stream from Capacity Obligation is supposed to cover part of the investment costs of generation companies. Because of that, the occurrence of price spikes is justified no more. Therefore, price cap setting and Capacity Obligation are usually used jointly [2]. The advantage of Capacity Obligation is that it guarantees the specified reserve capacity margin.

In the Strategic Reserve method, a certain amount of capacity is determined by a central body, normally the regulator, and kept out of the energy market as a reserve to be called for activation upon specific conditions such as capacity shortage in the spot market or high price formation in the energy market [12, 22]. Strategic Reserve is predominantly used to preserve the economically non-efficient old actual capacities in case of any exigent capacity shortage. From this point of view is a tool to address short-term capacity deficiency. Hence, this is a tool for urgent reserve provision rather than addressing the aforementioned missing money problem [23]. Another study in 2016 concludes that compared to an energy-only market, Strategic Reserve exacerbates the possibility of market power formation in the energy market, leading to a higher rate of options usage and higher market prices [24].

Although all the capacity mechanisms, to some extent, have a positive impact on the long-term and short-term supply adequacy, those in Figure 1 having an orange filling color are mainly effective for long-term adequacy, those in green are effective for short-term adequacy, and those in white boxes can address both concerns.

III. CAPACITY MECHANISMS IN THE WORLD

Although the debate about the superiority of Energy-only markets or EnCa markets is still ongoing, it seems EnCa markets are getting the high ground. Even though reliability, sustainability, and affordability are the three major aspects of the energy sector, there's a consensus that reliability has the highest priority [12]. Thus, several countries have already implemented types of CRMs, and some others have them planned. For instance, in its guideline for 2014-2020, The European Commission included the use of CRMs to form a European-wide framework for the establishment of CRMs [22]. Fig. 2 depicts the application of different CRMs in Europe and North America.

As stated earlier, CRMs are meant to deal with the missing money problem and assure resource adequacy in the generation sector.

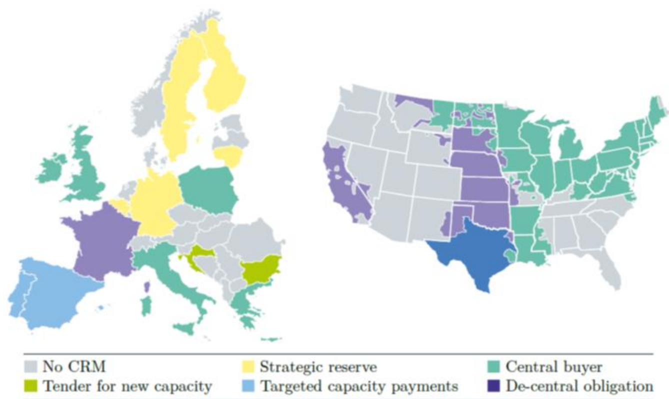

Fig. 2. Use of CRMs in Europe and North America [12]

Reviewing the realistic experiences in the world helps to understand the necessity and success of CRMs and their weak points. However, due to the dynamic nature of the electricity markets and frequent changes in their regulatory aspects, it is hard to track all the paths taken.

A. *New York ISO (NYISO)*

NYISO established a Central Installed Capacity (ICAP) market in 2003, which is still active in the present, almost unchanged. This Capacity market is executed every half year. Similarly, there are monthly and spot capacity markets to deal with the mismatches. ISO determines the minimum requirement of capacity based on the reliability standard for Loss of Load Expectation (LOLE) which is 1 over ten years [14, 25, 26]. The change from the Central ICAP market to a Forward Capacity Market has been considered by NYISO several times. Yet the results could not provide sufficient motivation to pursue the change. The main reasons for this are reported as:

- Economic benefit for consumers is not clear nor sufficient.
- The long-term benefit is not significantly strong.
- Higher prices and a lower quantity of provided capacity would be probable.
- The time lag in a forward market can cause high investment risks.

It should be added that time lag may necessitate more Reliability Support Service Agreement (RSSA), which distorts the Forward Capacity Market. Still, excess support would be necessary for encouraging new entries [25].

B. *PJM Interconnection (eastern USA)*

Previously, PJM used the ICAP model to manage the installed generation capacity. Still, in June 2007, PJM launched the new Reliability Pricing Model (RPM) scheme, a central forward market for generating capacity 3 years before the delivery year. Also, Load Serving Entities(LSEs) can acquire their capacity obligation via bilateral contracts [14]. PJM uses a sloped demand curve instead of an inelastic minimum criterion to evade high prices in the capacity market [27]. Based on [22], the average payment for capacity in PJM is about 5.5 Euro/MWh.

C. Midcontinent Independent System Operator (MISO)

MISO includes 15 US states and also the Canadian province of Manitoba. The electricity market was launched in 2001 in its region. In the case of the capacity mechanism, MISO runs a central capacity auction called Planning Resource Auctions (PRA), similar to what is done in PJM. However, in MISO, the auction is executed only 2 months ahead of the delivery year for the predetermined 9 zones, and the demand curve is vertical. For the 2015-2016 delivery year, the capacity requirement was set to 136359 MW, based on the once in 10 years criterion. The prices within the 9 zones were between 3.29 and 150 $ per MW-day. LSEs are authorized to meet their obligations via self-supply, Bilateral contracting and buying from PRAs [14, 28].

D. ISO New England (ISO-NE)

ISO-NE is responsible for operating a power grid with more than 97000 MW installed generation capacity within the 6 states in New England. Like PJM, ISO-NE runs a Forward Capacity Market 3-year ahead of the delivery year, considering an administratively sloped demand curve. In other words, the minimum capacity requirement (again once in ten years) is a hard one, and high price spikes are probable in case of scarcity. Forward Capacity Market in ISO-NE is mandatory. If any generating capacity seeks to exit the capacity market temporarily or permanently, it must go through ISO-NE's cost review process [14].

Since June 2018, ISO-NE has amended its previous design of FCM; the amendment is called "Pay For Performance (PFP)." Historically, all the ISOs having a kind of market for capacity had a way to monitor resources to make sure they were available when scarcity conditions happened. But ISO-NE's PFP mechanism introduces separate payment for performance. In this way, all generating capacities participating in the FCM are subject to separate payments: "base payment" and "performance payment." It's worth mentioning that the performance element of revenue from FCM could be positive (in case of over-performance) or negative (under-performance) [29, 30].

E. Southwest Power Pool(SPP)

Southwest Power Pool (SPP) operates the power system in the central United States. Its territory includes 14 states with peak demand slightly higher than 50000 MW. There is no central capacity market in SPP. Instead, SPP requires LSEs to meet their reserve requirement via self-supply or bilateral contracting. Currently, in SPP, the minimum required reserve margin is set at 12% [14].

F. California ISO (CAISO)

California ISO (CAISO) obligations LSEs to meet their obligation in providing sufficient generation capacity via self-supply and bilateral contracts. Also, CAISO determines LSEs' flexible capacity obligations to ensure the system can sufficiently ramp up to follow the demand. If LSEs do not meet RA requirements, CAISO can use Capacity Procurement Mechanism (CPM) to get backstop capacity. In 2018, 1055 MW was procured via CPM with a total cost of around 78 Million dollars [14, 31].

G. Belgium & Sweden

Belgium and Sweden have introduced Strategic Reserves to ensure system capability in serving the peak demand in winter. The history of Strategic reserve in Sweden goes back to 2003, while Belgium started using this mechanism in 2014. Belgium uses a competitive tendering mechanism. However, the procured capacity has never been activated. On the contrary, Sweden has been forced to use the procured reserve capacity several times. Its annual cost in 2014 reached 13 million euros, far lower than the estimated shortage cost of around 90 million euros [12].

H. United Kingdom (UK)

Central capacity auctions in the UK were started in 2014, with the first delivery date in the winter of 2014 (four years ahead). The auction is also repeated 1 year before the delivery period so the market players can balance their position [12]. As well as the generation facilities demand side response and interconnectors are eligible for participation in the capacity auction. However, capacities receiving renewable subsidies are prohibited from entering capacity auctions. The demand curve is administratively slopped in the auctions to improve market performance. Fig. 3 depicts the result of the 4-year-head Capacity Market in 2016.

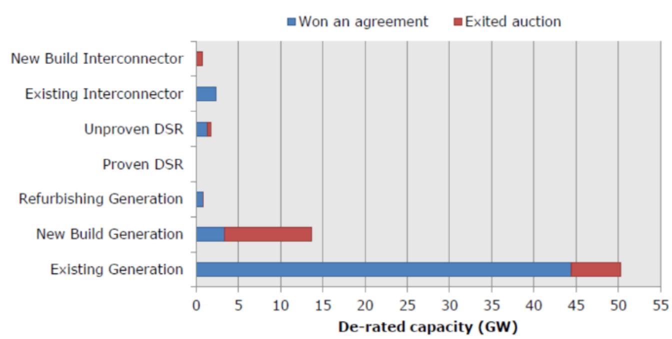

Fig. 3. Volume of awarded and exited capacity in T-4 CM in 2016 [32]

In the 2016 T-4 capacity auction, 52425 MW was procured, and the market was cleared at 22.5 £/kW when the price cap was set to 75 £/kW. It's worth mentioning that although the targeted capacity was set to 52000 MW, because of the sloped demand curve, 425 MW of extra capacity was awarded over the targeted level. For the first time in the history of capacity auctions in the UK, in the 2016 T-4 auction, 2500 MW storage capacity was awarded, too, from which 454 MW is new-built distribution-connected storage [32].

I. France

France has around 133 GW installed capacity and has been using decentral capacity obligation since 2015. All Load Serving Entities (LSEs) must procure sufficient certificates to meet peak demand. Certificate-owners could be generation facilities as well as demand side response. The certificates can be traded in a market or bilaterally. France is the first country that recognizes foreign capacities eligible for participation in capacity certificate trading [12]. For 2019, the forecasted capacity certificate by RTE is between 92.7 GW and 94.2 GW (Base scenario to high scenario). For 2018 the market reference price reached 9342 Euro/MW-yr [33].

J. Spain

Spain was one of the first countries to use Targeted Capacity Payment in 1997, but to adapt to European law, the mechanism was considerably reformed in 2007 [12, 34]. Spain was experiencing rising demand for electricity of 5%, and to encourage generation investment in the new form of Targeted Capacity Payment, the new generation facilities had a secure stream of capacity payment for 10 years. However, after the economic crisis in Europe and the intense decrease in electricity consumption, the incentive mechanism for new capacities was abolished in 2013. However, Spain still uses a Price-Based Capacity payment [12].

The incentive mechanism was very successful in encouraging investment in new generation facilities, and in the past decade, more than 20GW generation capacity was added to the system. The generation mixture in Spain is depicted in Fig. 4.

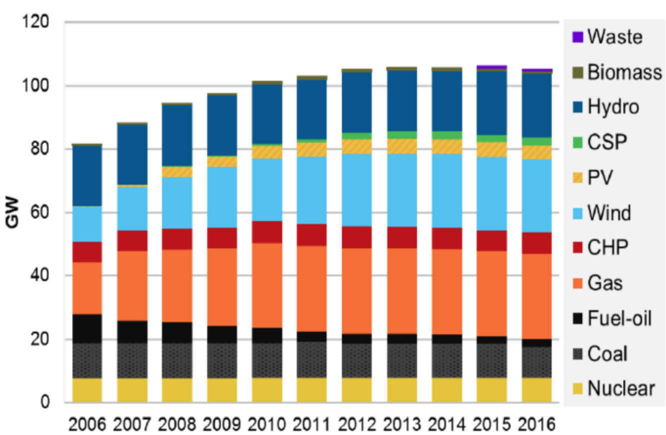

Figure 4: Installed generation Capacity in Spain [34]

The entrance of the new capacities was hit by the economic crisis and falling electricity demand. The highest electricity demand in Spanish history happened in 2007, with 45450 MW, and the peak demand in 2018 reached 40947. Such severe over-investments in the Spanish power system have caused some critics and doubts about the continuity of the capacity payment [34, 35].

IV. THE CAPACITY MECHANISM IN IRAN

Iran is a developing country that hosts numerous energy-intensive industries such as steel, Aluminum, copper factories, petrochemical complexes, automobile industries, etc. The peak demand has continuously increased, and the total installed capacity in 2020 slightly passed 85.4 GW. Fig. 5 shows the generation mixture in Iran Electricity Market (IREMA). It's worth mentioning that thanks to the ease of access to highly subsidized and cheap fossil fuels, renewable energies have a tiny share in total generation (less than 1 percent). However, in recent years, a feed-in-tariff mechanism has been introduced to support investments in renewable electricity [36].

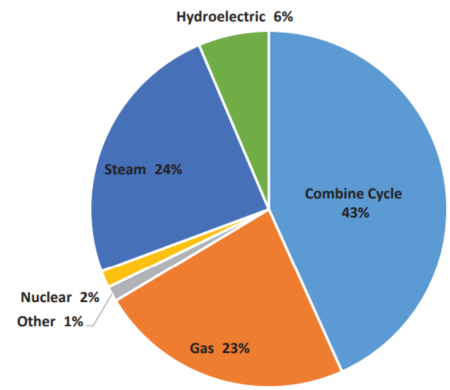

Fig. 5. Generation mixture in Iran in 2020-2021 [37]

As a developing country, Iran experiences a continuously increasing demand for electricity, especially on hot summer days, in which a lack of demand response due to highly subsidized consumption tariffs shifts the short-term security of electricity supply to a challenging priority. Moreover, the need for continuous economic growth and high dependency on fossil fuels highlights a long-term concern for the security of supply. Fig. 6 depicts annual peak demand and installed capacity during the last 20 years.

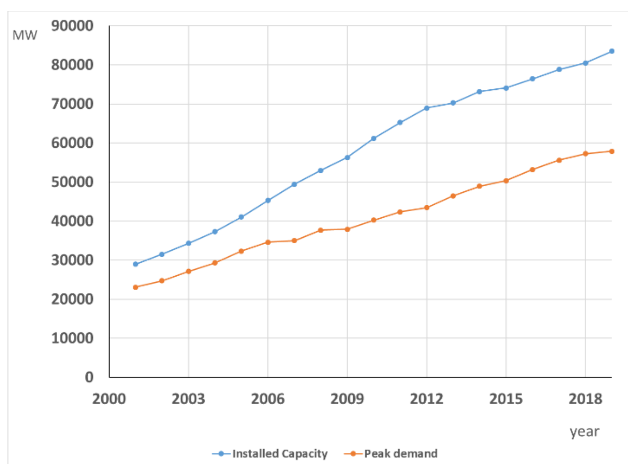

Fig. 6. Installed generation capacity v.s. Maximum annual demand [37]

Financial incentives for new generations have quite a history in Iran, and long-term guaranteed purchase agreements have been used for decades to boost investments and meet the increasing demand. Despite the increase in the installed generation capacity, due to some factors such as site-based deration, aging of the generation facilities, maintenance outages, water shortfalls, etc., a tight margin of generation in peak time has been a continuous problem that still threatens the security of supply, especially in hot summers.

A. Capacity Mechanism in IREMA

Since the generation margin in Iran has been tight, from the very beginning of the electricity market (IREMA) in Iran (2003), market-wide Capacity Payment (CP) has been part of the market design, and market founders preferred a priced-based market-wide capacity payment approach. Hence, every generating capacity offered in the Day-Ahead market is eligible to receive capacity payment, regardless of whether it is activated for energy production. Thanks to this design, generating companies benefit from a more reliable revenue stream, reducing their financial risk. Although the entrance of new generating capacity is boosted via the guaranteed purchase agreements, the Iranian capacity payment scheme doesn't have much to do with long-term supply adequacy. It's worth mentioning that, recently, and as a substitution for the guaranteed purchase agreements, a multilateral forward capacity market has been initiated to give financial incentives for the entry of new generation capacities.

Transition to a central capacity market has been suggested for IREMA, but establishing a competitive mechanism for capacity requires an acceptable margin on the generation side. Without it, there would be no competition, and almost all available generation capacity would be accepted within the capacity market. Furthermore, a lack of sufficient margin increases the possibility of market power in the capacity market, and price spikes would be inevitable.

Besides securing the revenue of generating companies from the market, Iranian capacity payment plays a critical role in the IREMA pricing methodology. Peak demand occurs in hot summers when the stored energy at the big dams is low, and electricity consumption due to cooling loads are high. In such conditions, the generation margin in IREMA is extremely tight and even negative; hence, price spikes formation is quite expected. Knowing this, regulators put a price cap on the energy market to limit the spikes and instead secured the capacity payment to deal with the missing money. Indeed, the energy market's cap price has been too low. Consequently, as Fig. 7 depicts, capacity payment includes a considerable share in the revenue portfolio of generating companies.

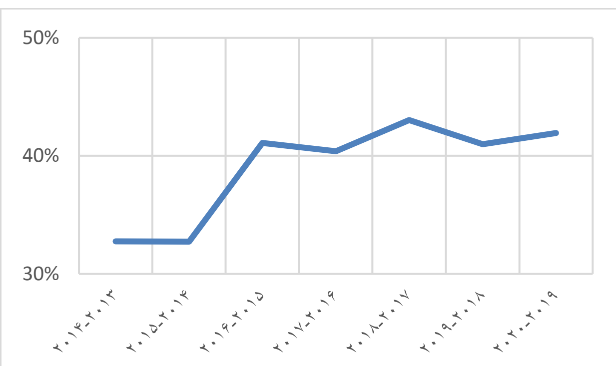

Fig. 7. Share of CP in the generated revenue in recent fiscal years [37]

B. *The negative impact of Capacity Payment*

Besides all the advantages of capacity mechanisms, their prominent negative effect is decreasing market competitiveness. If the share of capacity payment in the total revenue increases, the generation companies would be less sensitive to the competitive energy market. In other words, the generation companies care less if they lose within the energy market since they already have a considerable secure revenue stream out of capacity. This may lead to underperformance of the energy market and excess cost for the buyers.

In the case of market-wide capacity payment, this disadvantage is more disturbing since the capacity revenue is determined out of any competition or supply/demand. In this situation, the transparency of the market falls, and due to the conservative behavior of most regulators, overvaluation of capacity payment is more likely to happen.

Such a high capacity payment would be more comforting for old and non-efficient generating units that their winning chance in the energy market is limited to certain hours in the peak time. Regulators in IREMA believe that the burden of capacity payment is defendable compared to the replacement cost of these old peak-time generating units. They tried to overcome the negative impact of Capacity Payment by introducing Capacity Payment Factors (CPF).

C. *CPFs in IREMA*

The negative impact of capacity payment in suppressing the market competitiveness is a high risk in low demand periods in which the energy market price drops. In peak periods, the major part of the generating capacities would be called upon to produce energy. Capacity Payment ensures they remain available and ready to generate during these periods. However, in low load conditions, the market uncertainty increases, and generating companies face higher acceptance risk. In such conditions, if the capacity payment secures high revenue, generating companies may lose their sensitivity to act competitively within the market. This may lead to higher price offerings despite the low load condition. Because, if the high offer price is accepted the generating company will enjoy it, and if not, it still has a reliable and high revenue from the capacity payment.

In IREMA, capacity payment factors are defined and incorporated to fix this problem. In short, the price of capacity payment at each hour is defined as the annual base availability price multiplied by the CPF of that specific hour. Annual Base Availability Price (BAP) is the same for all 8760 hours in a year and is determined by the regulatory board. On the other hand, CPF for each hour can be different, and, as is implied in (1), it is reversely proportional to the expected reserve margin. This way, in low-demand periods, CPFs drop. Consequently, the revenue from capacity payment falls, and generating companies have to rely seriously on the revenue from the energy market.

$$CPF_{h,d,Yr} = \begin{cases} \dfrac{1}{Res_{h,d,Yr}} & Res_{h,d,Yr} > \alpha \\ \dfrac{1}{\alpha} & Res_{h,d,Yr} \leq \alpha \end{cases} \tag{1}$$

As seen in (1), the value of CPF at each hour has a reverse relationship with the expected reserve margin in that hour ($Res_{h,d,Yr}$). Moreover, CPF values in the hours with extremely low reserve margin ($Res_{h,d,Yr} \leq \alpha$) are saturated to prevent the very high capacity payment in those hours and keep the generating units sensitive to the competition in the energy market.

According to the legislation issued by the regulatory board, CPFs are required to be consistent with BAP. In other words, applying CPFs shouldn't cause the equivalent average payment for availability to differ from BAP, which is called 'the preserving condition.' This condition is enforced using the corrective factor k_1, which is defined in (2). Since the payments for the ancillary services are considered as part of the capacity payment, the predicted payment for these services (Pay_AS) is included in calculating k_1.

$$k_1 = \frac{BAR \times \sum_{h=1}^{24} \sum_{d=1}^{365} \left(AvCap_{h,d} \right) - Pay\_AS}{BAR \times \sum_{h=1}^{24} \sum_{d=1}^{365} \left(\epsilon_{h,d,Yr} \times AvCap_{h,d} \right)} \quad (2)$$

Having k_1 calculated as the corrective factor, the final values of CPFs are determined using (3).

$$CPF^{*}_{h,d,Yr} = k_1 \times CPF_{h,d,Yr} \quad (3)$$

The real CPFs for the 2018-2019 fiscal year vary between 0.223 and 3.99 but to obtain more clear visualization in Fig. 8, the moving average of the reserve percentage as well as CPFs is illustrated.

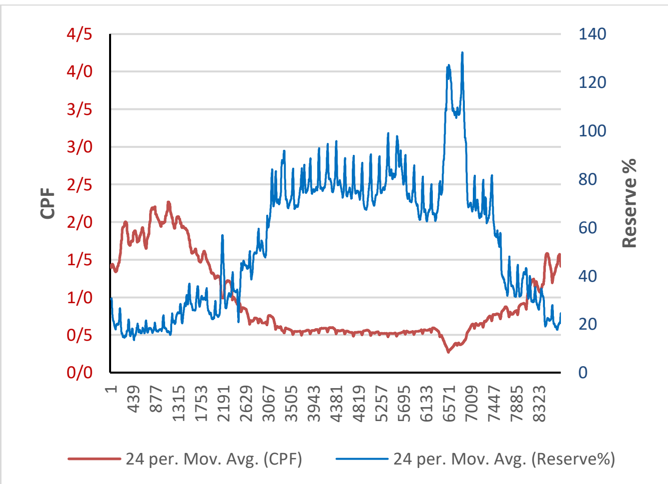

Fig. 8. Reserve% and CPF in 8760 hours of the 2020-2021 fiscal year (starting on June 22nd) [38]

Comparing minimum CPF (0.22) with its maximum (3.99) implies that capacity payment in the lowest-load hour was about 18 times lower than the peak hour in that fiscal year. In other words, using CPFs in low-load periods deteriorates the intensity of the Capacity Payment so that the competitiveness of the energy market is preserved.

V. CONCLUSION

Price volatility, missing money problems, generation revenue insufficiency, and boom-bust cycling in investment are some major concerns regarding energy-only electricity markets. Capacity mechanisms are defined mainly to address the aforementioned hardships. Since its beginning, IREMA has been equipped with a capacity payment mechanism, which produces a substantial revenue stream for the generating companies. Hourly CPFs are designed for proper valuation of available capacity throughout the year and to preserve market competitiveness. However, since capacity payment forms 40% of the annual revenue of the generating companies, it has a prominent role in total electricity cost. Consequently, the determination of the base price of capacity payment is a challenging task.

VI. REFERENCES

[1] Hirth, L. and F. Ueckerdt. Ten propositions on electricity market design: energy-only vs. capacity markets. in Sustainable Energy Policy and Strategies for Europe, 14th IAEE European Conference, October 28-31, 2014. 2014. International Association for Energy Economics.

[2] De Vries, L.J., Generation adequacy: Helping the market do its job. Utilities Policy, 2007. 15(1): p. 20-35.

[3] report, N., Glossary of Terms Used in NERC Reliability Standards. Jan. 2020, North American Electricity Reliability Corporation.

[4] Bernstein, M.A. and J. Griffin, Regional Differences in the Price-Elasticity of Demand for Energy. 2006, RAND Corporation.

[5] Burke, P.J. and A. Abayasekara, The price elasticity of electricity demand in the United States: A three-dimensional analysis. Aug.2017, Centre for Applied Macroeconomic Analysis(CAMA).

[6] Hogan, W.W., On an "Energy only" electricity market design for resource adequacy. 2005, Citeseer.

[7] Brown, D.P., CAPACITY MARKET DESIGN: MOTIVATION AND CHALLENGES IN ALBERTA'S ELECTRICITY MARKET, in The School of Public Policy PUBLICATIONS. March 2018, Univercity of Calgary.

[8] Joskow, P., Symposium on 'capacity markets'. Economics of Energy and Environmental Policy, 2013. 2(2): p. v-vi.

[9] 9. Newbery, D., Missing money and missing markets: Reliability, capacity auctions and interconnectors. Energy Policy, 2016. 94: p. 401-410.

[10] 10. Duggan, J.E., Capacity market mechanism analyses: a literature review. Current Sustainable/Renewable Energy Reports, 2020. 7(4): p. 186-192.

[11] 11. Stoft, S., Power system economics: designing markets for electricity. Vol. 468. 2002: IEEE press Piscataway.

[12] 12. Bublitz, A., et al., A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms. Energy economics, 2019. 80: p. 1059-1078.

[13] 13. Hildmann, M., A. Ulbig, and G. Andersson, Empirical analysis of the merit-order effect and the missing money problem in power markets with high RES shares. IEEE Transactions on Power Systems, 2015. 30(3): p. 1560-1570.

[14] 14. Bushnell, J., M. Flagg, and E. Mansur, Capacity markets at a crossroads. Energy Institute at Hass Working Paper, 2017. 278.

[15] 15. Lévêque, F., Competitive electricity markets and sustainability. 2007: Edward Elgar Publishing.

[16] 16. Bhagwat, P.C., et al., An analysis of a forward capacity market with long-term contracts. Energy policy, 2017. 111: p. 255-267.

[17] 17. Cramton, P. and S. Stoft, Forward reliability markets: Less risk, less market power, more efficiency. Utilities Policy, 2008. 16(3): p. 194-201.

[18] 18. Cepeda, M. and D. Finon, Generation capacity adequacy in interdependent electricity markets. Energy Policy, 2011. 39(6): p. 3128-3143.

[19] 19. Hasani, M. and S.H. Hosseini, Dynamic assessment of capacity investment in electricity market considering complementary capacity mechanisms. Energy, 2011. 36(1): p. 277-293.

[20] 20. Gusilov, E., capacity market vs energy-only market. The case of Romania. March 2018, Romania Energy Center.

[21] 21. Oren, S.S., Generation adequacy via call options obligations: Safe passage to the promised land. The Electricity Journal, 2005. 18(9): p. 28-42.

[22] 22. Stamtsis, G. and V. Lynchnaras. Integration of capacity markets into the European electricity market. in Proceedings of the DEMSEE 2015 Conference, Budapest, Hungary. 2015.

[23] 23. Finon, D., G. Meunier, and V. Pignon, The social efficiency of long-term capacity reserve mechanisms. Utilities policy, 2008. 16(3): p. 202-214.

[24] 24. Bhagwat, P.C., et al., The effectiveness of a strategic reserve in the presence of a high portfolio share of renewable energy sources. Utilities Policy, 2016. 39: p. 13-28.

[25] 25. Hibbard, P., et al., NYISO Capacity Market Evaluation of Options. Analysis Group Economic, Financial and Strategy Consultatnts, 2015.

[26] 26. NYISO, Installed capacity manual. 2019, New York Independent System Operator.

[27] 27. Hobbs, B., Capacity Markets: Principles & What's Happening in the US. 2010, Economic and Social Research Council.

[28] Spees, K., S.A. Newell, and R. Lueken, Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint. 2015.

[29] England, I.N., The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future. 2015, October.

[30] ISO-NE, Manual for the Forward Capacity Market (FCM). ISO New England Inc. Available online: https://www.iso-ne.com/participate/rules-procedures/manuals. 2019.

[31] 31. Hildebrandt, E., et al., Annual Report on Market Issues & Performance. 2018, Department of Market Monitoring – California ISO.

[32] 32. ofgem, Annual Report on the Operation of the Capacity Market in 2016/2017. 2017, www.ofgem.gov.uk.

[33] 33. RTE, Bilan Êlectrique 2018. 2019, RTE, https://bilan-electrique-2018.rte-france.com/marches-mecanisme-de-capacite/.

[34] 34. Wynn, G. and J. Julve, Spain's Capacity Market: Energy Security or Subsidy. London: Climate Home (http://www. climatechangenews. com/2016/12/13/spains-hidden-e1bn-subsidy-to-coal-gas-power-plants/), 2016.

[35] 35. REE, THE SPANISH ELECTRICITY SYSTEM - End of year forecast 2018. 2020, Red Eléctrica de España.

[36] 36. Ministry of Energy. Feed-in Tariffs for buying renewable Electricity from consumers. 2016; Available from: http://www.satba.gov.ir/suna_content/media/image/2016/09/4798_orig.pdf.

[37] 37. IGMC, Iran bulk power grid - Key indicators. 2020.

[38] 38. IGMC. Annual capacity payment factors. 2021; Available from: https://www.igmc.ir/Documents/EntryId/337132.