2013 Annual Report

2013
Electric Market
Trends & Analysis

EMSC

smart KPX KOREA POWER EXCHANGE

  

Electricity Market Trends & Analysis

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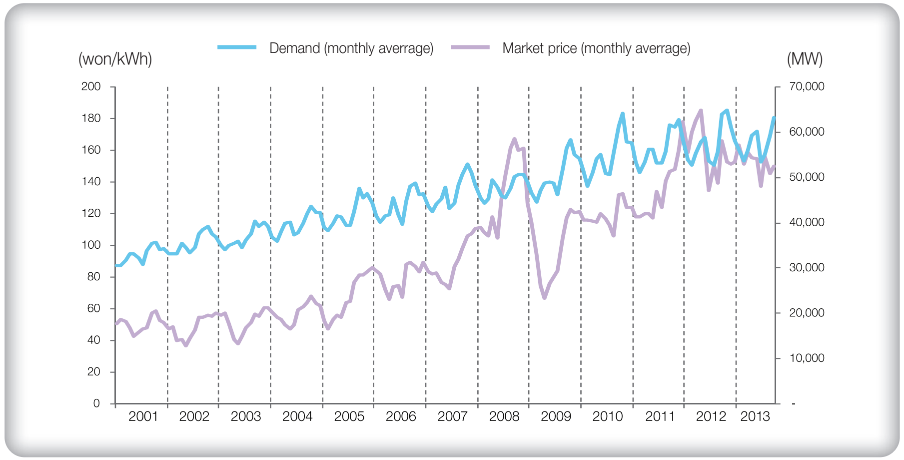
Market Overview

Market History



Market Opening

1999 Set up 『the Basic Plan[1] for the Electricity Industry Restructuring』.
Design the Basic Plan for the Implementation of the CBP Market.
Complete designing Market Operating System and introduce RSC (Resource Scheduling & Commitment).

2000 Establish Korea Power Exchange (KPX).
Start Operation of Simulated CBP Market.
Enact the revised Electricity Business Act to Implement the Restructuring of the Electricity Industry.

2001 MOCIE approves the Electricity-Market Rules and Detailed Guidelines.
KPX acquires establishment permission and the wholesale market opens.
Set up the ancillary services settlement standards.

Operation of the CBP

2002 Establish an Electricity Market Surveillance Committee.

2003 Introduce a Direct Purchase System.

2004 Introduce a new type of Community Energy Supply business.
Withhold the Introduction of the TWBP, originally planned to start from 2003.

Improvements in the CBP

2005 Research study for CBP Market improvements.

2007 Initiate the 1st phase[2] of the Market Development Plan

2008 Open a demand-response market.

2009 Research study on the advanced market mechanism for a more competitive CBP market.

2010 Introduce zonal pricing(In-land and Jeju Island).

2011 Turn over pumped-storage generators from KEPCO's coal-fired subsidiaries to KHNP (Hydro & Nuclear Company).

2013 Introduce the Soft Price Cap.

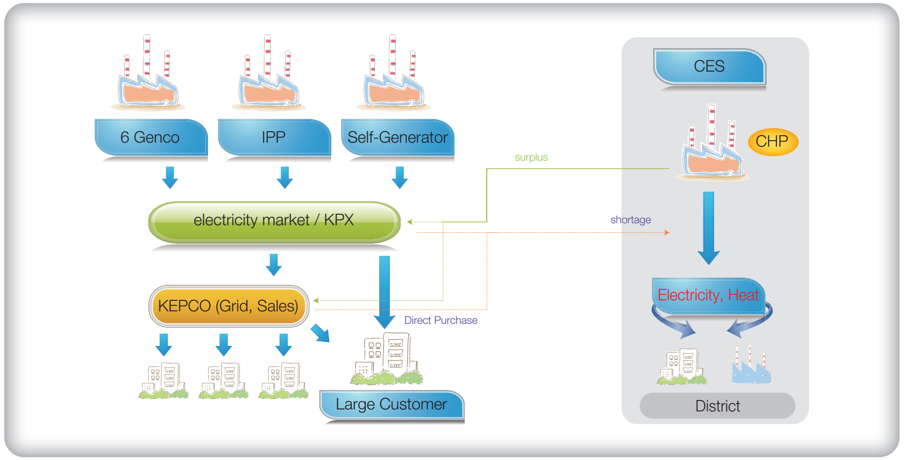
1) 1st phase: Cost-Based Pool (CBP) (2000~2002),
2nd phase: Two-Way Bidding Pool (TWBP) (2003~2008),
3rd phase: Retail Competition (Since 2009)

2) Key features of the 1st phase of the Electricity-Market Development Plan are as follows: Unification of capacity payment prices for generator fuels ; imposing the fixed-cost of the transmission network connection-unit and basic-price of incoming power on the reference capacity price; introduction of a regional capacity-price and differentiation of the capacity-factor by season/time; abolition of a two-tier price-system for base load/non-base load generators and introduction of a regulated market-price (RMP); introduction of the transmission loss-factor in order to provide geographical signals for successful power-generation plant investment

Market and Trading Structure

Market Structure

Since the Korean electricity market was officially opened on April 2, 2001, the market remained a Cost-Based Pool, an early phase of the pool-driven market competition system. The market has the following characteristics that are designed to minimize restructuring risks involved in the transition procedure and to stimulate market competition:



First, all electricity traders are obliged to participate in the electricity market(Gross pool) in accordance with article 31 of the Electricity Business Act that came into force on Dec. 23, 2000. However, article 8 of its bylaw allows an exception for those GenCos who signed Power Purchase Agreements (PPA) with the Korea Electric Power Corporation (KEPCO), a major electricity company, can supply their generated powers to KEPCO without trading through the pool. The act also approves financial Contracts for Differences (CfD) for market participants who seek to avoid risks.

Second, the Korean market has paid different trading settlement depending on the generator type to stabilize market prices since its opening although the forms varied. The initial market was divided into two: the base-load market and the non-base load market. Today, the Korean market applies the several payment adjusting factors to each of the generator types. The rationale behind the distinction between the base-load market and the non-base load market was as follows: power generators are generally classified into base load generators, such as nuclear and coal that often have high fixed costs and low variable costs and non-base load generators such as LNG and oil that have low fixed costs but high variable costs. While base-load generators can maintain stable prices because they are less affected by external variables such as fuel prices and foreign exchange rates, non-base load generators are more responsive to such variables. The two-tier pricing system was implemented in 2000 when the base load plants accounted for 81 percent while the non base load generators accounted for the rest 19 percent. Under such circumstances, pricing by a single system marginal price (SMP, market price) could trigger volatility of the whole electricity market because of price ups and downs of the non base load generators affected by the external factors. Another possibility was that profit imbalance might occur between KEPCO and GenCos or between GenCos. In 2007, a new form of regulated base load market price program was introduced in place of abolishing the base load marginal price (BLMP) program. The capacity price of the base load plants was cut to the level of non-base load generators in the same year. In 2008, the regulated base-load market price program was revised again and thus the two-tier pricing of the non-base load plants and the base-load plants was improved to a single SMP. However, the two-tier pricing structure has been technically maintained by applying the SMP coefficient to the GenCos which are practically owned by electricity retail company (then KEPCO), which hold its shares over 50%. In 2012, the target generators to stabilize the market prices started including the coal-fired centrally dispatched generators of private companies. In 2013, the Soft Price Cap was established to set price cap (PC)[3] as the reference capacity price setting price and to adjust the settlements by applying the lower price between the market price and the price cap.

3) A provision on the "Soft Price Cap" was added to the Electricity Market Rules in 2013. For more details, refer to Rule Changes.

Third, GenCos are mandated to provide ancillary services in accordance with dispatch instructions from KPX. The Electricity Market Rules specify that scheduled generators must provide ancillary services such as automatic generation control, governor-free, reasonable reserve margin, reactive power supply, black starts and others which were not compensated during the initial stage of market operation and, practical ancillary-service settlements were prepared in May 2002 and by readjusting the compensation of governor-free and automatic generation control, actual settlement standards were set up in September 2006. Those standards were intended to facilitate the stable operation of the power system without inflicting economic disadvantages on the GenCos, which provide frequent ancillary services by powering their hydro-generators or pumped-storage generators.

Fourth, the operation of pumped-storage generators has been steadily improved to minimize the operational cost and stabilize the system operation in the market. How to operate the pumped-storage generators are very important and the operation effects are huge in the market or system operation. The operation of the pumped-storage generators has long been reviewed for improvement. As part of the efforts, the rules on the Price Setting Schedule (PSE) and settlement method of the pumped-storage generators were revised in the Electricity Market Rules in 2011 and 2012. In the past, scheduling PSEs, the generation capacity of pumped-storage generators was considered while the pumping demand was not. The imbalance between generation and demand of the pumped-storage generators distorted the market prices. Therefore, in 2012, the rule was revised to reflect the pumping demand in the PSEs. Moreover, the settlement standard was changed in many aspects to encourage the GenCos to optimize their operation of the pumped-storage generators. That includes the settlement standards for generation, pumping and generation efficiency of pumped-storage generators. The whole improvements in 2012, related with pumped storage generators, strengthened the market price signal and enhanced the market efficiency by giving more advantages to market participants. Also, we have been encouraging the market participants by optimizing the operation of the pumped-storage generators in order to minimize the whole costs and uphold the efficiency of the system operation[4].

Power Trading Structure

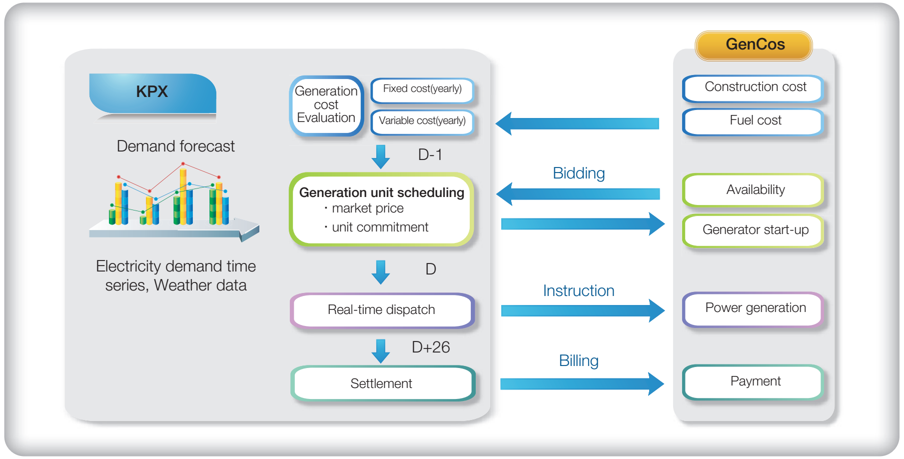
Trading payments in the electricity market consists of capacity payments (CP), scheduled energy-trading payments (SEP), and the uplift settlement charges. A scheduled energy-trading payment is settled in the market for the energy actually generated in accordance with the quota allotted in the Price Setting Schedule (PSE). The uplift settlement is the difference between the settlement based on the PSE that does not consider network or generator constraints and the actual settlement made as a result of the power-system operation. It is composed of Constrained-on (CON) that is not allotted in the PSE, but generated by power system constraints and Constrained-Off (COFF) that is allotted in the PSE, but not generated by power system constraints. Capacity payment is made based on the generators' availability declared by power producers (generation companies) until one day before the trading day. Capacity-price reflects the investment cost and fixed operation costs of generators. The Market Rule mandates that the Cost Evaluation Committee will decide the reference capacity price annually by selecting a standard power plant and calculate the capacity price applicable to that standard power plant.

The Korean electricity market is operated by the following procedures: assessment of power generation costs, forecasting of power demand, bidding, setting up the PSE, determining the SMP, setting up the Operation Schedule, real-time generation including CON, COFF, metering and then settlements. A distinctive characteristic of the Korean electricity market is that it is a CBP where generators are not allowed price bidding but quantity. So variable-cost curves have to be calculated for price setting in the market. As the variable costs, however, cannot be accurately identified in real time, the Cost Evaluation Committee determines the actual variable-costs a month earlier by assessing variable cost factors of each power plant.

Power demand forecast is conducted one day before a trading day by KPX. The demand forecast is on a hourly basis of the given trading day. Bidding is open until 10:00 of the

4) Rules on price setting schedule and settlement method of pumped-storage power generators are to be amended starting 2012.

previous day of the trading day. Unlike other bidding markets that bid on the supply quantity and the price at the same time, bidders in the CBP can present only the hourly availability of their power generators, respectively. The PSE is drawn in consideration of the demand forecast, cost per generator, bid information or availability in order to meet the power-system demand at the minimum cost. Apart from the technical characteristics of power generators, constraints such as transmission constraints[5], heat supply constraints, fuel constraints and others are not considered at this stage.



The SMP is set by hourly marginal costs based on the PSE. The set SMP is announced by 15:00 one day before the trading day. The real-time Operation Schedule for the actual power system on the trading day is drawn up in a way that can reflect the several system constraints such as transmission constraints and fuel constraints; and in a way that can meet the power demand at the lowest cost. On the trading day, power is generated according to real-time power system conditions. Then the amount of generation per generator is measured in real-time and settled by the hourly market-price.

5) However, the HVDC transmission constraints are to be considered.

Market Governance

Regulator: Korean Electricity Regulatory Commission(KOREC)

In April 2001, the KOREC was established under the Ministry of Commerce, Industry and Energy (then MOCIE and currently the Ministry of Trade, Industry and Energy, MOTIE) to create a fair competitive environment for electricity companies, review issues concerning the rights of electricity consumers and settle disputes related to the electricity business[6]. The commission is composed of not more than nine members including a chairman who is appointed or commissioned by the President through the recommendation of the Minister of MOTIE.

KOREC is authorized to set up a legal and institutional framework where all market participants can compete on a leveling field. The commission can create and establish diverse mechanisms needed to properly monitor the electricity market. The commission also supervises the GenCos and the retailer to protect consumers from unfair behaviors of the market players and makes every effort to restructure the power industry to offer better services to the consumers.

Detailed responsibilities include: creating the standards and rules for the electricity business; supervising electricity companies to ensure that they are abiding by the rules; resolving disputes between GenCos or consumers and electricity companies; monitoring and investigating electricity companies' unfair behaviors; enforcing corrective measures for the investigated violations; and introducing competition through the power industry restructuring[7].

Surveillance Body: Electricity Market Surveillance Committee

Electricity market surveillance activities are closely related to those of the regulator, providing technical support to the efforts made by KOREC. In November 2002, the

6) See Article 53 of the Electricity Business Act for further details.
7) See Article 56 and Article 57 of the Electricity Business Act for further details.

Electricity Market Surveillance Committee was founded under KOREC in accordance with the Electricity Market Rule to monitor and invoke sanctions against prohibited and unfair behaviors as specified in Article 21 of the Electricity Business Act. The committee is composed of not more than nine members, including a chairman. The members are commissioned by the chairman of KOREC among regulatory officials and the executive director of KPX and experts specialized in the electricity market. In February 2003, the Secretariat for the Electricity-Market Surveillance Committee was formed and a regulatory official of KOREC was commissioned as Secretary-General of this body while the Market Monitoring & Analysis Office of KPX performed the practical roles of the EMSC secretariat.

Market Operation Committee: Rule Amendment Committee

The Market Operation Committee refers to a decision-making body to identify market operation issues that need to be addressed. Each committee consists of the representatives of market participants performing different functions (generators, IPPs, retail business operators), government branches and independent experts specialized in various fields of the electricity industry. The committee should draw an objective and the fair conclusion on issues that requires a decision when adding a specific rule or procedure to the market rule. It listens to the diverse opinions of the concerned parties and independent experts who have a deep knowledge and experience in the concerned matter and tries to reflect governmental policy in the conclusion. The Committee, specifically includes the Rule Amendment Committee, the Cost Evaluation Committee, the Information Disclosure Committee and the Dispute Resolution Committee.

The roles and membership of the Rule Amendment Committee is as follows:

The Rule Amendment Committee deliberates and makes decisions on proposed amendments to the Market Rules that are the most critical documents specifying standards, procedures and methods of market operation. KPX and market participants can propose an amendment to the Market Rules and the Ministry of Trade, Industry & Energy (MOTIE) can also recommend an amendment. The Rule Amendment Committee is composed of not more than nine members including a chairman, the CEO of KPX. Members of the committee consist of representatives from regulatory official, market participants and outside scholars and experts.

Market Operation Committee: Cost-Evaluation Committee

The price in the CBP is set by power generation costs that consider the variable costs of each power generator. Therefore, whether cost factors are assessed fairly or not has great impact on market pricing. The Cost Evaluation Committee convenes monthly to assess cost-related factors in a fair and transparent way. The committee is composed of six to nine members, including a chairman.

Market Operation Committee: Information Disclosure Committee

The Information Disclosure Committee deliberates and makes decisions on matters concerning the efficient management and timely provision of the market information. The market participants' bidding strategy and investments in new facilities are based on market information. That is why the timely provision of information is crucial in ensuring a fair and efficient market and enhancing the reliability of market operations. The committee makes decisions on KPX members' and non-members' requests for information disclosure and reviews and determines measures on information security; preventing possible disadvantages to members caused by the disclosure. The committee is composed of not more than nine members, including a chairman.

Market Operation Committee: Dispute Resolution Committee

Disputes that have occurred in the course of market and power system operations are to be settled by the Dispute Resolution Committee. Unlike other committees that have a fixed membership, its members are appointed only when there is a dispute to handle. Both parties to a dispute are entitled to choose three members from among the member pool. There are 24 specialized member candidates who have a certain expertise in areas related to the power industry such as the law, electrical engineering, accounting, economics, business administration, IT and other fields.

2013 Market Overview

Market Issues

In 2013, the market price hit a record high of 257.57 won/kWh at Hanlim CC ST #1 at 15:00 on October 1. Meanwhile, the market price hit a record low of 40.76 won/kWh at Hadong #7 at 14:00 on February 10. The average market price decreased 5.4% year on year, to 152.10 won/kWh. The power demand increased 1.6% from 2012. The price-setting percentage of base load generators with low variable cost decreased to 1.0% in 2013 from 2.3% in 2012. Market prices fell despite the year-on-year increase in power demand. In our analysis, this fall is mainly due to the decreased fuel costs of LNG and oil and the higher installed capacity growth rate than the power demand growth rate.

In 2013, the installed capacity growth rate stood at 4.3% with the new entry of LNG CC generators such as Ohsung CC (March, 770 MW), Yulchon CC #3 & #4 GT (June, 572 MW), Pyeongtaek CC #5 & #6 GT (July, 484 MW), Bugok CC #3 (August, 382 MW), and Sejong Combined Heat and Power Plant (November, 530 MW).

The peak demand hit 76,522 MW at 11:00 on January in winter 2013. The power demand growth rate stood at 0.7%, which is lower than the average growth rate at 4.1% of the past six years.

Month	Market Issues
January	· Because of the rising exports, decreasing average temperatures and the Korean New Year's Day holidays fell on in February not January, the power demand increased 5.6% year on year. · The peak demand hit an annual and seasonal high of 76,522 MW at 11:00 on January 3. · SMP increased 2.9% year on year due to the rise in the price-setting percentage of LNG. On the other hand, the average unit price(total payment/total trading volume) decreased 5.0%, which was affected by the decrease in the payment adjusting factor applied to the KEPCO subsidiaries and the decrease in the fuel cost of bituminous coal.
February	· The peak demand increased 0.5% year on year because the temperatures were above average for the time of year and the Korean New Year's Day holidays and the resulting fewer working days (the holidays fell on in January 2012 on the lunar calendar, but they fell on in February in 2013.). · The LNG fuel cost increased 6.2%, but all the other fuel costs decreased year on year. · Despite the increase in LNG fuel cost, the price-setting percentage of oil decreased and that of base load generators increased. Accordingly, the monthly average SMP decreased 5.7% year on year to 150.79 won/kWh.
March	· The trading volume slightly decreased by 0.3% year on year because of the rise in average temperatures and the resulting fall in demand for heating load. Meanwhile, the SMP significantly decreased by 14.3% and the average unit price by 16.8% as the global oil prices fell and the fuel costs of all the power sources except LNG plummeted. · The installed capacity for trading in the electricity market increased by 418 MW from the previous month with the new entry of 13 generators including Byullae Energy and Bugok CC #3 despite the shutdown of Namjeju D/P (diesel power plant, 40 MW).

Month	Market Issues
April	· The average power demand increased 4.2% year on year to 55,986 MW due to the decrease in average temperatures. Meanwhile, the peak demand increased 0.8% to 64,872 MW due to the decrease in monthly lowest temperature. · The SMP increased 3.22% year on year to 163.33 won/kWh on the back of the rise in price-setting percentage of oil generators. The average unit price decreased 3.8% to 97.0 won/kWh, however, as the fuel costs of all the fuel types except LNG decreased.
May	· The monthly average temperature slightly went down year on year when compared with abnormally high temperatures in 2012. Yet, the energy trading volume increased 2.5% year on year on the back of the boosted economic activity and the resulting 3.2% increase of exports. · The SMP decreased 11.9% year on year to 151.04 won/kWh. That is because the fuel costs of oil and LNG remarkably decreased 15.2% and 9.8% respectively during the same period, and the price-setting times by oil generators decreased.
June	· The average power demand increased 1.1% with the rising demand for cooling load caused by the higher temperatures compared with the previous year. However, the growth rate was not as significant as 4.8% in June 2011 and 3.2% in June 2012. · The SMP decreased 11.2% to 158.13 won/kWh as the fuel costs had been on decrease since early 2013. However, the SMP increased 4.7% because of the month-to-month increase in fuel costs of LNG and oil and the increase in power demand.

Month	Market Issues
July	· The average power supply increased 2.4% with the year-on-year increase in exports of the semiconductor and other energy guzzling businesses and the increase in demand for cooling load caused by the higher seasonal temperatures. The peak demand, however, decreased 1.1% to 72,112 MW with effective demand response and energy-saving policies. · The fuel cost of LNG remained high for two consecutive months, but it decreased 15.1% year on year. Yet, the fuel cost of oil began to fall by 4.5% from the previous month and 16.1% year on year. · The SMP decreased 16.1% year on year to 155.29 won/kWh because all fuel costs drastically fell down.
August	· The average power demand increased 2.4% year on year with the boosted economic activity and the resulting increase in exports and the increase in demand for cooling load caused by the higher seasonal temperatures. The peak demand, however, decreased 0.4% to 74,015 MW with effective demand response and energy-saving policies. · The fuel cost of LNG decreased 0.5%, but the fuel cost of oil began to rise, showing a 0.8% increase from the previous month. All the fuel costs remained low year on year. · The bid ratio of installed capacity decreased by 0.9%p year on year because of large-scale base load generators subject to the long overhaul period in time of summer peak demand.
September	· The fuel cost of LNG increased 0.3% while the fuel cost of oil began to decrease, falling 0.3% from the previous month. All the fuel costs remained low year on year. · The SMP increased 2.1% to 136.88 won/kWh because of the increase in price-setting percentage of oil owing to the decreased year-on-year supply capability, falling 11.2% from the previous month with the increased SMP of base load generators because of the Korean Thanksgiving Day holidays.

Month	Market Issues
October	· The peak demand increased 5.3% to 64,911 MW and the average power demand increased 4.7% year on year to 55,036 MW because of the Korean Thanksgiving holidays falling in on September and the increase in exports. · The fuel cost of LNG began to fall, decreasing 2.0% from the previous month, which is up 0.9% year on year). The fuel cost of oil fell for two consecutive months, decreasing 0.4% from the previous month, which is a significant year-on-year decrease of 14.9%. · The SMP increased 3.6% year on year to 155.80 won/kWh affected by the rise in fuel cost of LNG and price-setting percentage of oil.
November	· The fuel cost of LNG continued to fall following the previous month, decreasing 3.9% during the period, which is a 10.6% year-on-year increase. The fuel cost of oil decreased 0.8% from the previous month, which is a significant year-on-year decrease of 16.6%. · The SMP increased 4.3% year on year to 145.05 won/kWh affected by the rise in fuel cost of LNG and price-setting percentage of oil.
December	· The peak demand increased 0.4% and the average demand decreased 1.0% with the year-on-year increase in average temperatures and the energy-saving campaign. · The fuel cost of LNG increased 6.2% from the previous month and 6.7% year on year. By contrast, the fuel cost of oil continued to fall, decreasing 1.8% from the previous month and 10.4% year on year. · The SMP decreased 9.4% year on year to 149.90 won/kWh affected by the fall in price-setting percentage of oil.

Rule Changes

The Rule Amendment Committee convened three times in the first half of 2013 and once in the second half of the year. One revision was made by the approval of the Trade, Industry & Energy Minister without the deliberation of the Committee in accordance with Article 9.3.4 on the emergency revision of the Electricity Market Rules.

In the first half of the year, the Rule Amendment Committee passed five proposals for rule revision including the introduction of the Soft Price Cap designed to curb the utility rate raising factors that come with the increased price-setting percentage of high-cost generators because of the falling power reserve margins; the introduction of Renewable Energy Certificate (REC) trade market and Renewable Portfolio Standard (RPS) cost as KPX was designated as the institute for REC; and the revision of procedures for bid regarding temperature-adjusted availability of combined cycle generators. In the second half of 2013, the Rule Amendment Committee passed four proposals for rule revision. The revisions include the revision of procedures for bid regarding ambient temperature-adjusted combined cycle generators, adding to one emergency revision regarding improvement in the standard for zonal pricing. Major rules revised in 2013 are as follows:

Introduction of the Soft Price Cap

With the recent fall of reserve margins, high-cost generators became price-setter more frequently and average unit prices have rosen. As a result, KEPCO is faced with mounting pressure to raise utility rates. In response, The Soft Price Cap was introduced to set price caps (level of cap is variable cost of marginal generator which was chosen for calculating the capacity price) and to adjust the settlements by applying the lower price between the market price and the price cap. To prevent possible damage from the generators of which variable cost is higher than the price cap, in that case the variable costs are guaranteed. Furthermore, this system is in force only for a limited period of time.

Introduction of Renewable Energy Certificate (REC) trading market and Renewable Portfolio Standard (RPS) commitment cost

Korea Power Exchange (KPX) was designated as the institute for REC in Korea and the guidelines about management and operation of RPS were revised. With the revision of the Electricity Market Rules, Renewable Energy Certificate (REC) trading market was established and the Renewable Portfolio Standard (RPS) commitment cost has been reimbursable in the electricity market since March 2013. The REC Working Council under the Rule Amendment Committee was established to work on the REC prices and RPS, to enact provisions on the division of the REC trading market into the contract market and the spot market, and to lay out settlement rules for the RPS commitment cost.

Revision of procedures for bid regarding temperature-adjusted availability of combined cycle generators

Issues arose because of the inaccurate calculation in bidding the installed capacity of combined cycle generators. Even when the Korea Meteorological Administration (KMA) announced its weather forecast including the temperatures by the hour, the hourly forecast temperatures were missing in the availability bids for combined cycle generators and instead only the four tracks categorized by the daily high, the daily low, and the daily average were available. In response, the Electricity Market Rules were revised so that the hourly forecast temperatures by KMA are included in the bids, and when the temperatures are updated, the corresponding bids are revised and up for the bid again.

Improvement in the standard for zonal pricing

It was predicted that it would be impossible to set the market prices in Jeju Island in price setting scheduling if the HVDC line 2 is constructed and the amount of transmission increases between in-land and Jeju Island. In response, the standard for zonal pricing was revised to set electricity market prices considering the generators in all the zones when zonal prices cannot be calculated.

Improvement in the settlement rules for overbid generators for power system stabilization

Before this revision of the Market Rules, the generators can make a loss when they are ordered by central dispatch center to delay the schedule for overhaul or test in emergency of insufficient supply and changed bid volume. That is because capacity payment shall be made as much as the initial amount of bid even when the generation capacity increases with a revised schedule. The revised Electricity Market Rules stipulates that capacity payment shall be made including the increased availability in the applicable cases in order to compensate for the contribution. Such a revision was made in order to encourage more real-time Temperature adjusted Availability (TA) of generators and thereby to enhance accuracy in calculating the reserve.

Improvement in bid rules for temperature-adjusted combined cycle generators

In the first half of 2013 when the Temperature adjusted Availability (TA) came into force, issues emerged that TA and Re-offered Availability (RA) were mixed. In response, the revised Electricity Market Rules now stipulates that only the change in TA shall be calculated compared with the first submission. The goals of the revision are to set a clear standard for TA for combined cycle generators and to build a fair environment in the electricity market by preventing possible bid errors.

Change in standard for registration of combined cycle generators

Recently gas turbine (GT) and steam turbine (ST) generators in some areas with shoddy electric-power grid were inevitably connected to different bus lines. The disrupted connections evoked registration issues because the generators can be registered as one generators only when connected to one bus, resulting in multiple registrations according to the rule. As a result, the change in variable cost raised the market prices and lowered the inherent GT-ST synergy effect and highly efficient power generation of combined cycle generators. In response, the revised Electricity Market Rules stipulates that the generators in the same process of a combined cycle generator shall be registered as one generator even when not connected to the same bus.

Other: Revision of power purchase financial guarantee rules, etc.

Other revisions in the Electricity Market Rules in 2013 include the revision of financial guarantee rule for power purchaser, revision of procedure for additional tax levied to the members, and reflection of name change of the Ministry of Trade, Industry and Energy[8].

8) For more information about the revisions of the Electricity Market Rules, visit www.kpx.or.kr.

Market-Monitoring Activities

Market monitoring refers to activities that stimulate fair electric-power trading and facilitate competition in the market by monitoring prohibited behavior specified in the Electricity Business Act and other unfair behaviors in the electricity market or by taking sanctions. In recent years, the electricity supply and demand lasted unstable and the rolling blackout occurred in Korea in September 15, 2011. Against this backdrop, there is growing interest in stable power supply and operation of the electricity market in the National Assembly and the Board of Audit and Inspection of Korea, the public as well as the media across the country. The role of market monitoring is expected to grow further. The Electricity Market Surveillance Committee focused on advancing the framework for the above activities until 2007. The Committee continued to make every possible effort in ensuring the effectiveness of the activities and the fairness of the market. In 2013, further efforts were made to strengthen market monitoring activities in accordance with market conditions and the major activities include:

Market monitoring activities to uphold fairness and efficiency

We conducted the following market monitoring activities on the market participants to build a fairer and more efficient electricity market:

First, the number of the real-time availability tests for centrally dispatched generators increased to four from two in 2013 to review validity of availability for bidding, as part of the effort to boost market monitoring activities. In laying out a plan for the availability tests, moreover, the tests targeted the generators in need for improvement and unplanned dispatch orders were made.

Second, financial penalty was levied on the members who violated the Electricity Market Rules. The results of availability tests were analyzed every quarter in 2013. For the generators that powered lower output than declared availability, they were subject to a bill for financial penalty decisions in the Electricity Market Surveillance Committee. The financial penalty was issued to the generators that powered lower output than declared availability at the time of Korea's September 15 rolling blackout, for the first time since the establishment of the electricity market. Since then, availability tests have been given steadily and more frequently, imposing financial penalty on the generators with lower output than expected.

Third, field inspection was conducted mainly on the rarely-examined small-sized members in order to level up market monitoring activities. According to the Electricity Market Rules, self-generator installers can trade up to less than 50% of the annual total power generation. The two rounds of tests in the first half and the second half of 2013 respectively were conducted and the results show that all the self-generation installers comply with the rule. Under the same Rules, community energy supply businesses must operate self-generators to produce and supply heat and power in summer when heat demand in the grid is larger than the minimum generation capacity. All the community energy supply businesses were confirmed to comply with the rule.

Investigation into unfair capacity payment (CP) during the especially low load period

In 2013, an investigation was conducted to look into properness of the capacity payment during New Year's Day and Korea's Thanksgiving Day holidays of the year. The national audit in 2013 cast doubt on the properness and as a follow-up measure all of the 24 centrally dispatched generators were examined in terms of the dispatch order stand-by status during the national holidays both in the field and through document. The examination was focused on if the overhaul was conducted to the extent that the generators could not operate during the stand-by period. The investigation result shows that no unfair capacity payment was made during the holidays.

Improvement to the Electricity Market Rules and the detailed operation rules

In 2013, multi-faceted efforts were made to improve market monitoring institutions in order to enhance effectiveness of market monitoring and lay groundwork for the relevant infrastructure. First, detailed guidelines were laid out regarding the financial penalty standard and amounts for the violators of the Market Rules. Before the revision of the Rules, the violation patterns were not defined and the need for the more detailed guidelines was growing. In response, the fourth Electricity Market Surveillance Committee enacted reinforced financial penalty rules in 2013. Second, measures will be considered for the return of the differences in capacity amount of the generators that powered less than the amount of dispatch order in availability tests because of the faults by GenCos. According to the proposal, the return is expected to be made on the trading day (24 hours). The proposal will be discussed in the Rule Amendment Committee in 2014.

Attending international expert meetings in the developed countries and other activities to upgrade market monitoring capability

In 2013, we attended the Energy Intermarket Surveillance Group (EISG) in an effort to level up our market monitoring capability and strengthen our public relations through the network with international exports. In the meeting, we gave a presentation on the status of the Korean electricity market and discussed the best practices on the regulation of the energy industry in the developed countries. We also participated in the specialized training program on the public sector regulation and strategies by the Public Utility Research Center (PURC) in the United States. The program helped us develop our market monitoring capability further by deepening expertise and updating the international trend in the public sector regulatory policy.

Monitoring the electricity market and publishing monthly/quarterly/annual reports

In order to monitor the electricity market, we conducted daily monitoring using the "Market Monitoring and Evaluation System." We also issued reports with monitoring indicators on a monthly, quarterly and annual basis to analyze the status of market operation and system operation. The published reports are open to the members and the public on the KPX website. The primary goal of market monitoring was to raise accuracy in availability bids. The efforts to enhance the accuracy were steadily made by always monitoring resubmission cases such as generator failures that include unexpected stops and generator start failures as well as availability tests, and by notifying the relevant issues to the members. Other activities were conducted as well to clear market monitoring issues, including the recommendation of revising the provisions related to resubmissions in the Electricity Market Rules.

Raising awareness among market participants and encouraging voluntary compliance

Starting 2013, we introduced the Market Monitoring Orientation Program for the private-sector members to raise their awareness on market monitoring and encourage their voluntary compliance with the market rules. We reached out to the new private-sector members joining the electricity market so that they could learn about the electricity market including market monitoring, regulations and trading (bids and settlements) and grow as exemplary market participants. Meanwhile, market monitoring seminars were also held for the existing members in the first half and the second half of 2013. The members joining the seminars deepened knowledge about monitoring criteria by learning about the current market monitoring issues such as the monitoring results, plan and the focus points to come, and the detailed guidelines about financial penalty. Opinions from the members were shared for our review in the seminars. Also, we continued our effort to encourage further market monitoring activities by operating certification program for excellent observants of the rules and dispel the negative impression on market monitoring.

Market monitoring plan and direction for 2014

In 2013, we conducted market monitoring activities to promote awareness on the importance of rule-observance and improved some relevant rules. Another effort was also made to enhance accuracy in availability, yet some generators failed the availability tests and violated resubmission rules through the year. Turning in 2014, we plan to drive up our market monitoring activities to help the members bid availability accurately and submit more accurate data to the electricity market while encouraging them to comply with the recent revisions of the Market Rules. In detail, monitoring will be focused on the compliance with the technical data of the generators by the members, encouragement and monitoring of compliance to the starting time of generators, and strengthening of preliminary market monitoring for the new private-sector members.

We will also continue to publish the Electricity Market Trends & Analysis and improve analysis indicators. By doing so, we expect to look into the effectiveness of the current indicators, explore new meaningful indicators and improve the current indicators to enhance the quality of our analysis. Improvements of the indicators will be reflected in the draft of the Market Trends & Analysis to conduct analysis effectively.

Major surveillance activities in 2013

Activities	Statistics
EMSC meetings (determinations by the EMSC)	5 (20)
Monitoring review meeting	2
Rule breaches & corrective measures imposed	6
Periodic market monitoring reports published	16

Market Summary

The Korean wholesale electricity-market as of 2013 was a Cost-Based market that based its prices on generation costs. The market is operated in the form of a day-ahead market that includes scheduled energy payments, capacity payments and ancillary service payment. As of late 2013, the number of market participants was 540 and up 521 compared with late 2001 at the time of the establishment of the electricity market and up 94 compared with 2012. The installed capacity of market participants increased 4.3% to 86,177 MW year on year with the entry of many LNG CC generators including Ohsung CC (770 MW) and Sejong Combined Heat and Power Plant (530 MW). The electricity market showed trading volume amounting to 479,520,000,000 kWh (1.6% increase, YoY), posting 42.1062 trillion won in settlement (1.4% decrease, YoY).

With regard to the monthly average power demand, it increased 6.2% year on year in January because of the rising economic indicators, the lower temperatures than those of the previous year, and the increased number of working days as a result of Korean New Year's Day holidays in February, not January in 2013. The increase was the most drastic one in 2013. Turning in February, however, the monthly average power demand decreased 2.6%, the most dramatic fall in the year because of the fewer working days by Lunar New Year's Day and the mild weather. In August, the demand increased 2.4% year on year because of the continued heat wave and the resulting increase in demand for cooling load as well as the economic recovery followed by the increase of industrial electricity use. The growth rate, however, was not as remarkable as that of 2012. The peak demand in summer of 2013 decreased 0.4% year on year. In November, the growth rate of power demand remained low because the monthly average temperature was higher from the previous year although there was rising demand for industrial electricity. In the following December, the trend continued, showing a decrease in power demand for the same reasons.

The average market price in 2013 decreased 5.4% from the previous year to 152.10 won/kWh. This decrease was mainly due to the decreases in power demand and fuel costs of LNG and oil, which consist of the major price-setting fuel sources. The fuel cost of LNG decreased 1.7% while that of oil decreased 13.2% from the previous year and they led to the fall in market prices. In 2013, the electricity market saw causes of rising price such as the decreased price-setting percentage of base load generators, long-term outage[9] of some nuclear generators. However, the factors were traded off with other factors such as the higher installed capacity growth rate (4.3%) over the power demand growth rate (1.6%). As a result, the market price decreased (about 5.4%), a more drastic fall than the decrease rate of major fuel costs (2.5%). The highest market price was 257.57 won/kWh set by Hanlim CC ST #1 at 15:00 on October 1. Meanwhile, the lowest market price was 40.76 won/kWh set by Hadong #7 at 14:00 on February 10 during the Lunar New Year's holidays.

Since the establishment of the electricity market, the SEP has increased every year due to the rising average power demand and fuel prices. On the other hand, the capacity payment decreased to 4.2670 trillion won in 2013 from 6 trillion won in the early period of the market. The drastic decrease is mainly due to the fall in capacity payment unit cost and the application of unified capacity price. With the decrease in capacity payment, its percentage out of the whole payment has been on the decrease from around 40% at the time of market opening. In particular, the percentage has hovered around 10% since 2008. In 2013, the percentage was 10.1%, a 0.3%p increase from 9.8% in 2012 because of the increase in installed capacity, introduction of electricity cap pricing, decrease in major fuel costs, and decrease in payment. With the continued decrease in the percentage of capacity payment since the market opening until recent years, there are lower incentives for bidding among the GenCos than before. Our analysis is that it can pose a barrier to new private GenCos entering the market. The GenCos are expected to choose a strategic bid in consideration of market prices. With the behavior pattern changes among the GenCos, we need to keep them from distorting the market

9) Wolsong #1 in outage with the termination of design life since October 29, 2012; nuclear generators in outage for replacement of faulty parts (Shin-Kori #1 between April 8, 2013 and January 4, 2014; Shin-Kori #2 between May 29, 2013 and January 9, 2014; and Shin-Wolsong #1 between May 29, 2013 and January 4, 2014)

prices by exercising their market power and put a regulatory policy in place for a fair and stable operation of the market.

In 2013, the generation output by the electricity market accounted for 96.6%, maintaining the over-90% share since 2001 at 94.7%. By contrast, the generation output by the private GenCos rose to 10.6% in 2013 from 0.4% in 2002. This significant increase is mainly due to the active market participation of GenCos such as SK E&S and GS EPS and the new entry of new renewable energy GenCos on support by the Korean government policy. The active market participation and policy support show a positive sign of stimulating the trading and competition among the market participants.

The installed capacity reserve in time of the annual peak demand hovered around 13 - 18% in the early days of the electricity market. However, the reserve fell to one digit starting 2006. In 2011, it fell to 4.1%, a record low since the market opening, triggering anxiety over electric-power supply. Over 2012 and 2013, entrance of new generators raised the increase rate of the installed capacity over the increase rate in peak demand. Accordingly, the installed capacity reserve stood at 7.5% as of January 3 when the annual peak demand took place. All through the year, new installation of generators continued and finally the installed capacity reached 86,177 MW as of late 2013. Accordingly, the overall power supply improved from the second half of the year.

In 2013, the installed capacity and generation output by fuel type made a merely 1% difference from 2011, a similar level. With the installation of many LNG generators in 2013, their installed capacity increased 12% year on year. On the back of the Korean government's policy for supply and promotion of new renewable energy, the growth rate of installed capacity of new renewable energy was 21.3%, the most significant increase out of major fuel sources.

The market shares of the KEPCO subsidiaries have changed only within ±3%p over the last eight years (2006 - 2013). The installed capacity of KHNP increased with new nuclear installations, but the growth rate was lower than those of the major fuels. The market share of KHNP decreased 11%p from 2006 due to generator failures and unplanned overhaul. Also, the market shares of the top three GenCos stood at 55% in 2013 from 65% in 2006 and therefore the market concentration has been mitigated.

Looking into the heat energy consumed to supply the unit power representing the market efficiency, the market heat rate in 2012 remained high at a time when the operating hours of nuclear generators were much shorter than usual due to long-time failures while the operating hours and price-setting percentage of other generators with high variable cost increased with the rising demand for electricity. In 2013, the market heat rate decreased to 2.01 Gcal/MWh year on year, showing increased economic productivity of electricity. In the year, there were price-pushing factors such as the decreasing year-on-year operating hour percentage of nuclear generators caused by the long outage at Shin-Kori #1 & #2 and Shin-Wolsong #1. The higher installation growth rate over the power demand growth rate pulled down both the fuel costs and the market prices.

The demand response(DR) market program was introduced in 2008 and the hour-ahead DR market was implemented as a pilot operation in 2009. The requirements for establishment of the DR market were revised in 2010. In 2012, the requirement for establishing the DR market was upgraded to cases where the supply reserve is expected to be below 4,500 MW. In an effort to closely coordinate the demand response market and power system operation in 2013, 30-minute-ahead DR market in case of emergency was introduced in addition to the day-ahead and hour-ahead DR market.

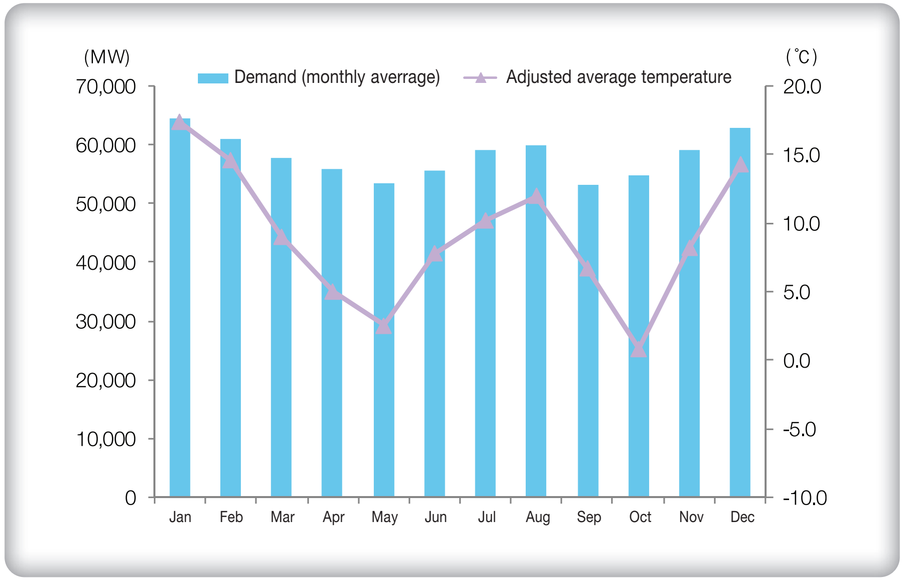
Increasing the correlation of availability to the power demand since the establishment of the market indicates continuous efforts to set up and implement the planned overhaul that reflects the power demand pattern. In particular, the correlation sharply increased to 0.712 in 2013 from 0.3881 in 2009. Our analysis is that the planned overhaul scheduled in response to the power demand contributed to the stable electric-power supply. The planned overhaul was scheduled avoiding the peak demand period in summer and winter. In the wake of the national rolling blackout in September 15, 2011, a number of improvements were also made to reduce uncertainty in demand forecast program by taking into actual weather and social conditions and operating the program 24 hours. Efforts to develop a new demand forecast program with much lower error rate or a technique responsive to uncertainty of the long-term demand forecast & forecast modeling may have affected these improvements.

Market Status

Power Demand

Power demand and Temperature

Trend of the monthly average power demand and average temperatures[10)]

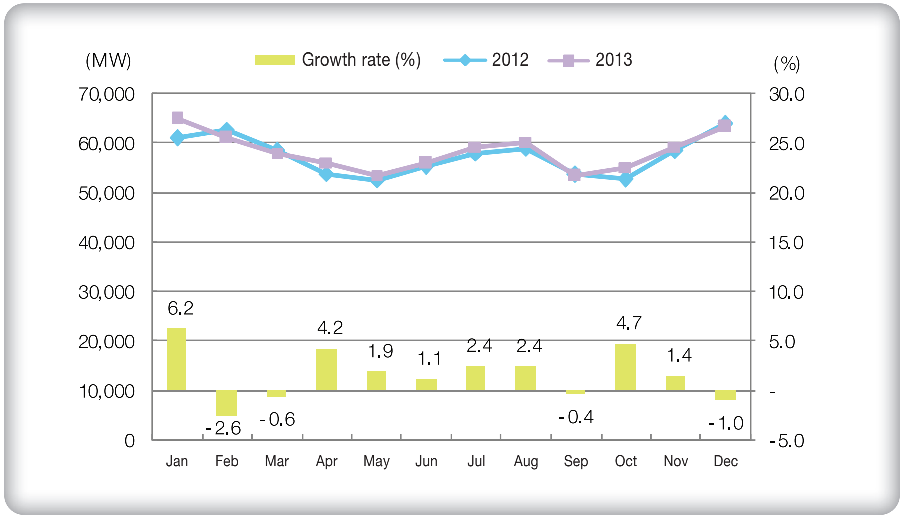


10) The average power demand is a value that excludes the pumping demand. The average temperature is the weighted average value of the regional power demand share to the average temperature of eight major cities such as Seoul, Busan, Daegu, Gwangju, Daejeon, Incheon, Suwon and Chuncheon. The adjusted value of the average temperature in the diagram above is the absolute value: lthe monthly average temperature - the lowest temperature responsive to the power demand (15.8℃)l.

Careful analysis of power demand is very important as it affects not only the electricity-market price, the planned overhaul or outage schedules of power-supply facilities; but also the entire energy industry, and its power-system operation and power-planning. The power demand in Korea is primarily effected by industrial production and weather conditions in the short term, adding to the determining long-term factors such as economic growth and industrial restructuring. Particularly, the trends of power demand change over the year must be analyzed in relation to temperatures since the demand fluctuates in accordance with cooling and heating loads. The correlation is well demonstrated in the charts below of the monthly average temperature and the monthly average power demand.

The monthly power demand in 2013 was closely related to the temperature as the previous year. In other words, power demand was high in summer and winter when the cooling and heating loads were high.

Monthly average power demand



The chart above shows the monthly average power demand and the year-on-year growth rates. Looking into the monthly average power demand, the demand for heating load increased with the increased number of working days because the Korean New Year's Day holidays fell on in February in the year and the temperatures were lower year on year. With the increased electricity consumption in the manufacturing sector and the increased demand for industrial use, the demand rose up most significantly of the year in January.

Turning in February, however, the power demand decreased 2.6% year on year, the lowest demand growth rate in 2013. The low number was affected by the New Year's Day holidays and the resulting decrease in the number of working days and the year-on-year high temperatures. The demand remained low in March as the demand for heating load decreased due to the temperatures higher than the previous year although the industrial electricity use increased.

From April to May, the demand for heating load increased due to the temperatures lower than the previous year. The industrial electricity use also increased due to the increase in exports. Overall power demand increased during the two months.

In summer, the average growth rates of power demand were 1.1% in June, 2.4% in July, and 2.4% in August. The rise in June was mainly due to the increased cooling load as a result of the high temperatures. The rise from July to August was due to the increased industrial electricity use with the economic recovery along with the increased cooling load. The seasonal peak demand hit 74,015 MW at 15:00 on Monday, August 19 in 2013 when the daily temperature was the highest in the year. In our analysis, the number decreased 0.4% year on year because of the daily temperature that was lower than a record high of the previous year and the energy-saving policy effect of the day.

In September, both the highest temperature and the average temperature increased year on year, but the average power demand decreased 0.4% with the energy saving policy effect. In October, the growth rate of power demand was 4.7%, the second high of the year with the rising electricity consumption in industrial businesses caused by the shift of Korean Thanksgiving Day holidays and a year-on-year increase of more than 7.2% in exports.

Typically in November seasonal demand upturns happen for heating load in winter and the power demand increases. The demand for residential and commercial electricity-use in nove decreased due to the higher temperatures than the previous year, but the demand increased affected by the demand for industrial electric power on increase since October in the year. In December, the power demand decreased 1.0% year on year. The demand for industrial electric power continued to rise, but the demand for residential and commercial electric power fell steeply in the month. The year-on-year 3.4℃ rise in monthly average temperature to 1.5℃ resulted in the decrease in demand for residential and commercial electric power, which is a stark contrast to the year 2012 when the peak demand hit in December due to the cold weather.

The annual peak demand in 2013 hit 76,522 MW at 11:00 on January 3, the same in winter as the previous years of 2011 and 2012. The day marked a record daily temperature low in December 2012, January and February 2013. The daily temperature on the day was 3.1℃ (year-on-year) lower than the previous average and that of 2012. The growth rate of power demand has been on the decrease since January 2013. The same trend had started in 2011, which is related to the mild economic growth rates during the same period in our analysis.

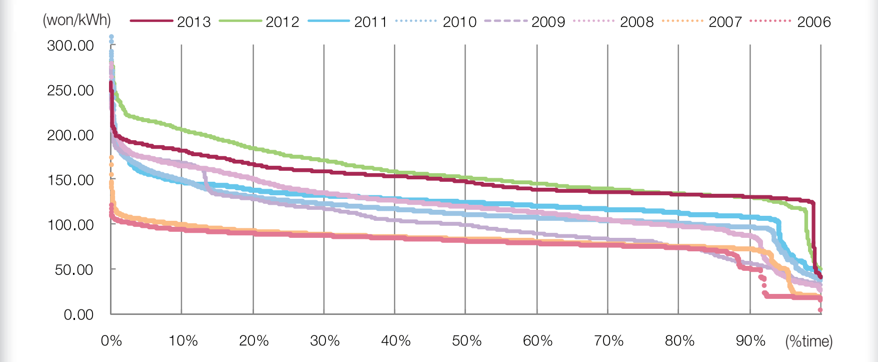
Market Price

Price Duration Curve

The price duration curve represents the probability distribution of the hourly market price (SMP). It shows the market price signals of power demand, fuel price and generation capacity mix.

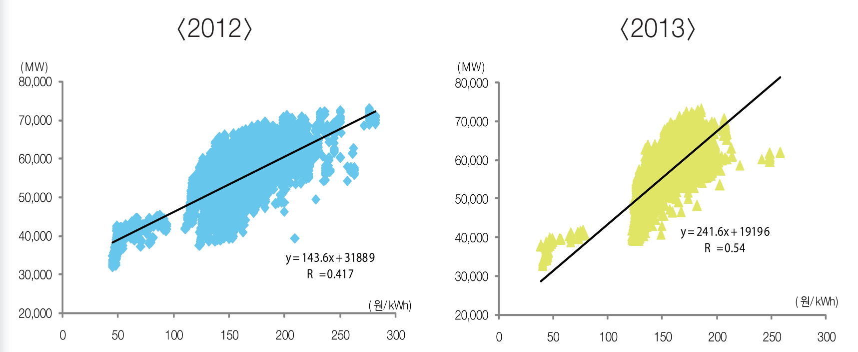
Classification	'07	'08	'09	'10	'11	'12	'13
Market price (won/kWh)	83.75	122.63	105.04	117.77	126.63	160.83	152.10
Year-on-year growth rate (%)	5.9	46.4	-14.3	12.1	7.5	27.0	-5.4

Price Duration Curve



Looking into the 2013 price duration curve[11] in comparison with that of 2012, the curve in the low price zone became steeper while the curve in the high price zone is moderate. The market prices were on the steady increase until 2012, but in 2013 the price decreased 5.4% year on year to 152.10 won/kWh. This fall is analyzed to have been affected by the drastic decrease of the high price zone on the price duration curve. Looking by track, the track above 150 won/kWh accounts for 46.7% of the whole, which is a 6.2%p year-on-year decrease. The track above 200 won/kWh accounts for 0.6%, much lower than 13.0% in 2012.

Distribution of the market price and the power demand ('12~'13)



11) With the introduction of zonal pricing in in-land and Jeju Island in 2010, the average system marginal price is calculated by the weighted average of the demand forecasts in in-land and Jeju Island.

This trend is well demonstrated in the diagram above on the 2012 - 2013 distribution of the market price and the power demand[12]. The distribution in 2013 is characterized by the slight year-on-year increase in correlation of the two factors. The increase shows that market prices and power demand became in linear correlation. The track between 100 won/kWh and 200 won/kWh markedly increased while the duration curve became steeper, which tells us that the volatility shrank in the market prices in anticipation of fluctuations in power demand because of the fall in price-setting percentage by of extreme ends of base load and peak generators.

The table below shows the annual hours by price and the average power demand by track in 2013. Most of the hours fell in between 100 won/kWh and 200 won/kWh. In reference to the diagrams above about "Price duration curve" and "Distribution of the market price and the power demand", the number of hours above the 200 won/kWh was 1,108 in 2012 and it sharply fell to 56 in 2013.

The annual hours by price and the average power demand by track

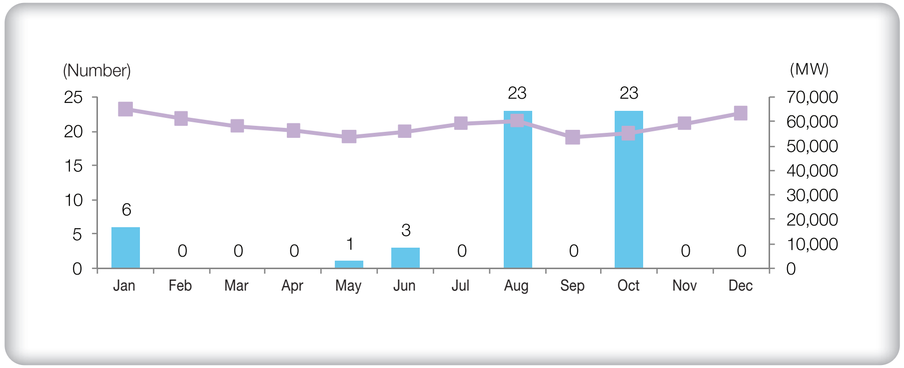
(Unit: won/kWh, MW)

Market Price	P<50	50≤P<100	100≤P<150	150≤P<200	200≤P
Number	69	19	4,667	3,949	56
Demand	36,449	40,415	50,867	60,861	64,405

The diagram above show a typical pattern all through the tracks between power demand and market prices as the more the power demand is, the higher the market price becomes. However, the diagram below on the number of hours with the price above 200 won/kWh by month shows that not only the power demand but also the decrease in availability caused by the planned overhaul and the generators in outage are significant factors in setting market prices.

12) The power demand here refers to the demand forecast in the Price Setting Scheduled Energy (PSE).

The monthly number of hours with the price over 200 won/kWh and monthly average power demand



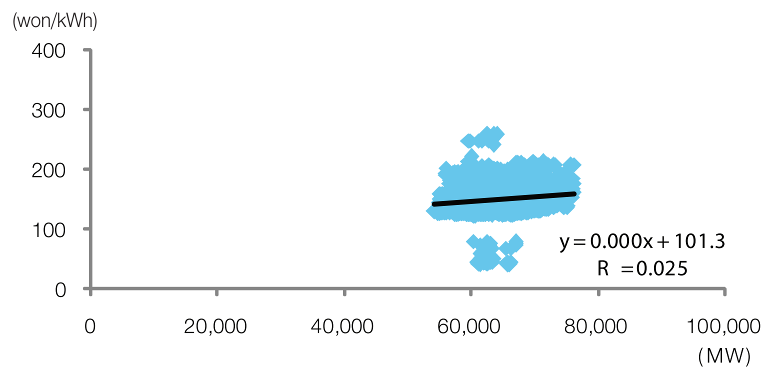
In August during the summer peak demand period and in October in autumn, the number of hours in the track above 200 won/kWh was 23, an annual record high. On the contrary, the number was six in January and zero in December both of which are with high monthly average power demand. May and June saw the price-setting hours in the 200 won/kWh track although the months show lower power demand than in February or December.

This development shows that market prices are often set high not in the typical peak demand period such as summer and winter. The price-setting times at above the 200 won/kWh track exists even in low power demand caused by the temporary decrease in availability in spring and autumn when planned overhaul is frequent. Also power demand in the 200 won/kWh track can be lower than in the other tracks.

The availability was allocated mostly to summer and winter days in anticipation of the peak power demand and as a result it decreased temporarily in spring and autumn days when the planned overhaul is concentrated. Our analysis is that the market price was thus set high despite the relatively low power demand. Again, it is confirmed that not only the power demand but also the decrease in availability caused by the planned overhauls and the generator outages are significant factors in setting market prices.

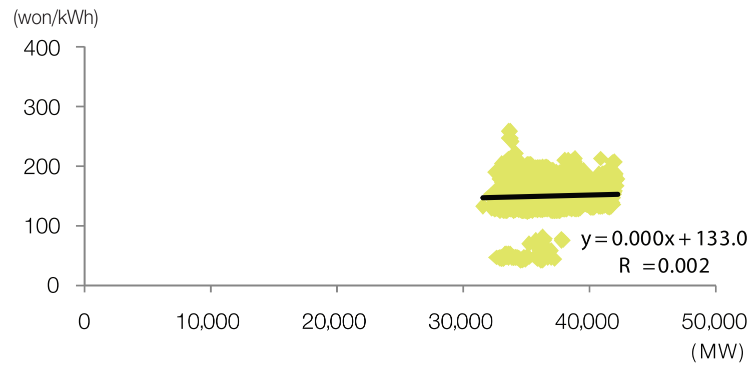
The influence of availability on the market price, however, is considered to be limited, which is confirmed in the graph below on the availability and the market prices. According to the graph, the coefficient between the two is almost zero, showing that there is no correlation between them. The limited influence is because availability under the current cost-based pool (CBP) means the physical capacity of generation for supply regardless of the market prices[13]. The same goes to the correlation between availability and market prices of base load generators. In other words, market prices are mostly affected by power demand. Availability affects only some peak load hours in high demand.

The distribution of availability and the market prices

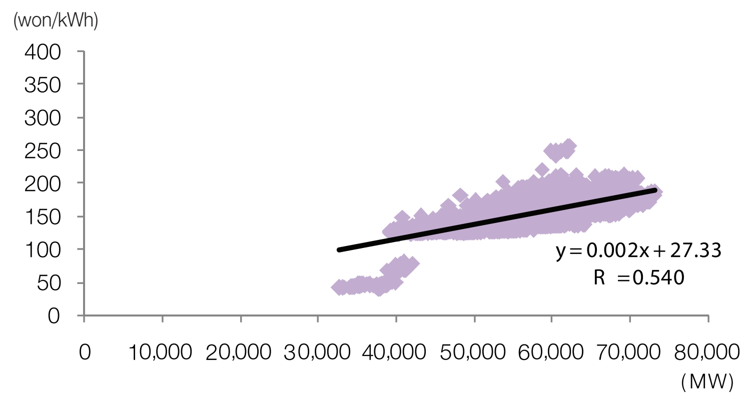


13) Obligation on electric-power supply by GenCos including the period for maintenance (see Section 14 of the Electricity Business Act and Section 13 of its Enforcement Regulations)

The distribution of availability of base load generators and the market prices

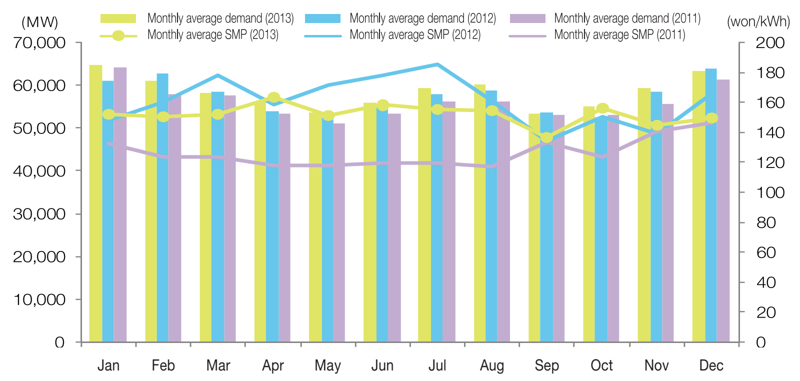


The distribution of power demand (estimate value) and the market prices



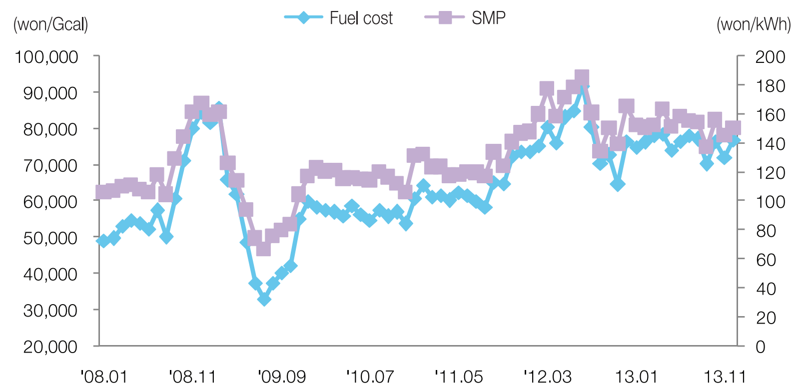
Meanwhile, looking into the monthly average market prices in 2013 by comparing them with those of the previous year, there are other contributors to the annual changes of the market prices. The diagram below about the monthly average power demand and market prices in recent three years shows that the market prices in 2013 changed less than the previous year. The same development is found in the standard deviation[14] of the monthly average market prices in recent three years (2011, 2012 and 2013).

Monthly average power demand and market prices in recent three years



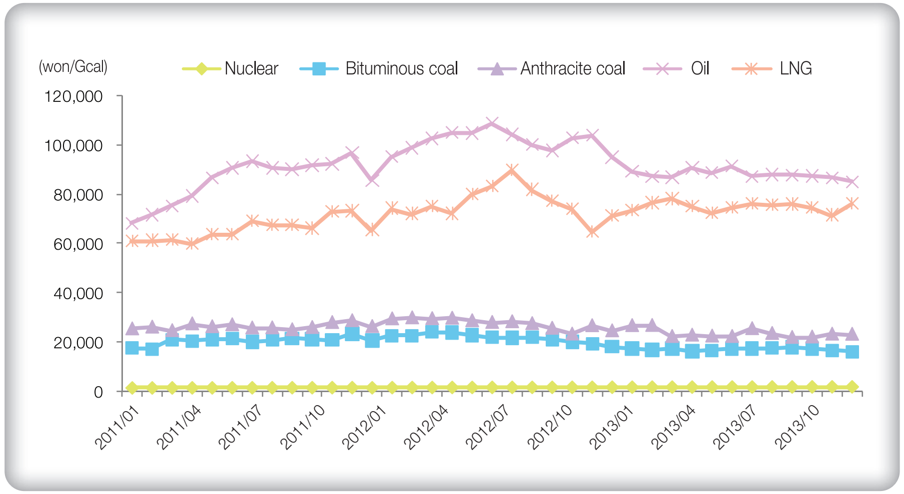
The decrease in fluctuations of market prices lies largely in three factors: deviation of the power demand, change of the correlation between power demand and availability, and change of fuel costs. In light of the standard deviation[15] in the power demand, the standard deviation in the monthly average power demand decreased in 2013 from the previous year. The decrease was, however, not enough to change the market price. Second, from the perspective of the correlation between power demand and availability, possibilities over changes in market price skyrocket if power demand and availability change in different directions. In 2013, no outstanding change in the correlation was found from that of 2012[16]. Third, in terms of change of fuel costs, the fuel cost of LNG that sets almost 90% of the market price increased more significantly in 2013 than in 2012[17]. The remarkable increase is shown in the two diagrams below on the monthly fuel costs by fuel type. The changes in fuel cost are considered to contribute to the fewer fluctuations of market prices in 2013 compared with 2012. The graph about fuel costs by fuel type shows the decreasing pattern of price-setting fuel types. The graph about monthly fuel costs and market prices in recent six years well demonstrates the close correlation between fuel costs and market prices. The monthly changes of fuel costs and market prices between 2008 and 2013 well demonstrate their close correlation.

Monthly fuel costs and market prices in recent six years



14) The standard deviation in 2013 decreased to 6.3 from 9.4 in 2011 and 15.2 in 2012.
15) The standard deviation in monthly average power demand was 3,710 in 2012 and 3,503 in 2013.
16) For more details, see the Market Participants' Behavior/Available Capacity by power demand sections in this report.
17) The standard deviation of LNG fuel cost was 6,341 in 2012 while it decreased to 1,752 in 2013.

Trend of monthly fuel costs by type (2012~2013)

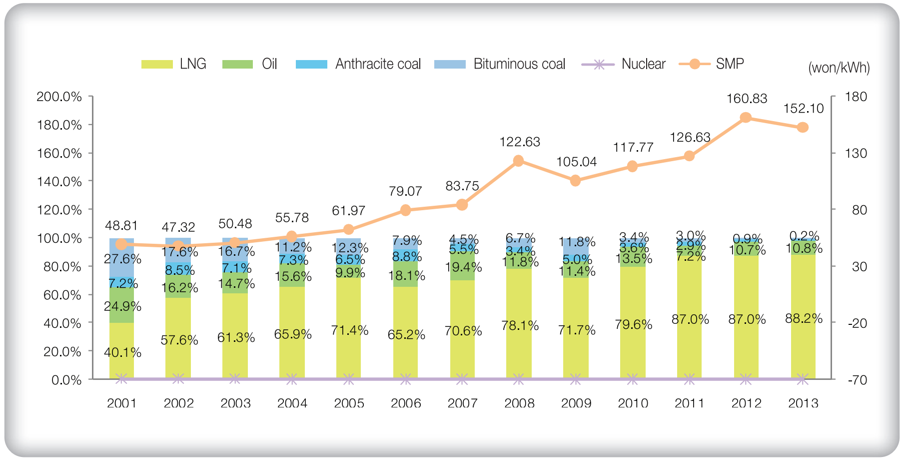


Fuel costs affect the electricity market much because the variable cost of peak load generators is a determining factor in the market prices. In the same context, the market prices decreased 5.4% year on year to 152.10 won/kWh mainly due to the fuel costs by fuel type.

Looking into the graph above about monthly fuel costs by fuel type, the fuel costs of most of the fuel types except nuclear power have been on the decrease since the first quarter of 2013. In particular, the annual average fuel costs of the major price-setting generators such as LNG and oil decreased 1.7% and 13.2% respectively, leading the decrease in market prices.

Changes in price-setting percentage by fuel type as well as changes in the costs of price-setting fuels are considered to affect market prices. The graph about price-setting percentage of generators by fuel type shows that the percentage of oil generators increased 0.1%p to 10.8% in 2013 from 10.7% in 2012. The percentage of LNG generators increased 1.2%p to 88.2% in 2013 from 87% in 2012. Meanwhile, the percentages of bituminous coal and anthracite coal decreased 1.3%p to 1.0% respectively in 2013. Our analysis is that the price-setting percentage of base load generators with low variable cost decreased while that of oil generators with high variable cost increased as much as the decrease. As a result, the market price rose up. As shown in the graph, the price-setting percentage of base load generators have been on the decrease for years.

Price-setting percentage of generators by fuel type



Meanwhile, looking into the market prices of the previous years, the market prices showed a similar pattern with the changes in the price-setting percentage of peak load generators (LNG and oil). Compared between 2011 and 2013, the price-setting percentage of LNG showed slight changes while the market prices fluctuated. In 2013, on the other hand, the price-setting percentage of LNG and oil increased as a contributor of pushing up market prices while the market prices decreased. The decrease in market prices lies largely in the fall in fuel costs of LNG and oil that account for most of the price-setting percentage. Our analysis is that the rise of LNG and oil in the price-setting percentage has traded off the fall in market prices.

A number of factors contribute to changes in market prices, including the hourly changes in power demand, planned overhaul, changes in availability caused by outages of generators, changes in fuel costs of price-setting fuel types, and price-setting percentages by fuel type. The market price in 2013 decreased 5.4% year on year to 152.10 won/kWh. As shown above, one of the major contributors that lower market prices is considered to be the fall in costs of major price-setting fuel types. In the electricity market of 2013, however, there were contributors that pushed up the market prices such as the fall in price-setting percentage of base load generators and long outage period of nuclear generators[18]. The rise in market prices, however, was traded off by the contributors that pulled down the market prices such as the slowing growth rate of power demand (1.6%) and the relatively high growth rate of installed capacity (4.3%). As a result, the market prices decreased 5.4% compared with the fall in average fuel cost of major fuel types (2.5%).

The highest market price in 2013 hit 257.57 won/kWh at Hanlim CC ST #1 at 15:00 on October 1, 8.6% decrease from 281.76 won/kWh, the highest price in 2012. The decrease was more significant than that of the average market price. Meanwhile, the lowest market price in 2013 was 40.76 won/kWh at Hadong #7 at 14:00 on the Korean New Year's Day holidays, February 10-14, in time of slow economic activity and the resulting low power demand. Earlier in 2012, the lowest market price was 44.8 won/kWh between 03:00 and 06:00 on the Korean Thanksgiving Day holidays on October 1.

Capacity Price and Capacity Payments

Korea's CBP which does not use prices as a bidding variable can systematically prevent a lack of facility investment that excessive price competition may bring about. Although the current capacity-payment system can help stabilize the power supply, it can also cause excessive investment or surplus facilities because payment is compensated for all GenCos' capacities in the biddings. Thus, it is worth reviewing availability by GenCo or generator regularly to check up usefulness of availability. Revisions of the Electricity Market Rules need to be considered with regard to the method of capacity payments to prevent shortage of facility investment and at the same time to secure a proper level of availability.

While the energy payment increased annually until 2012 due to the rise in power demand and fuel prices, annual capacity payment had stayed at the 6 trillion won level between 2002 and 2006 and has halved to 3 - 4 trillion won since 2007, sharply reducing its coverage ratio in total payments from 45.2% in 2002 to 17.2% in 2007, 11.4% in 2011 and 9.8% in 2012.

Payment amount and its ratio by type of payment[19]

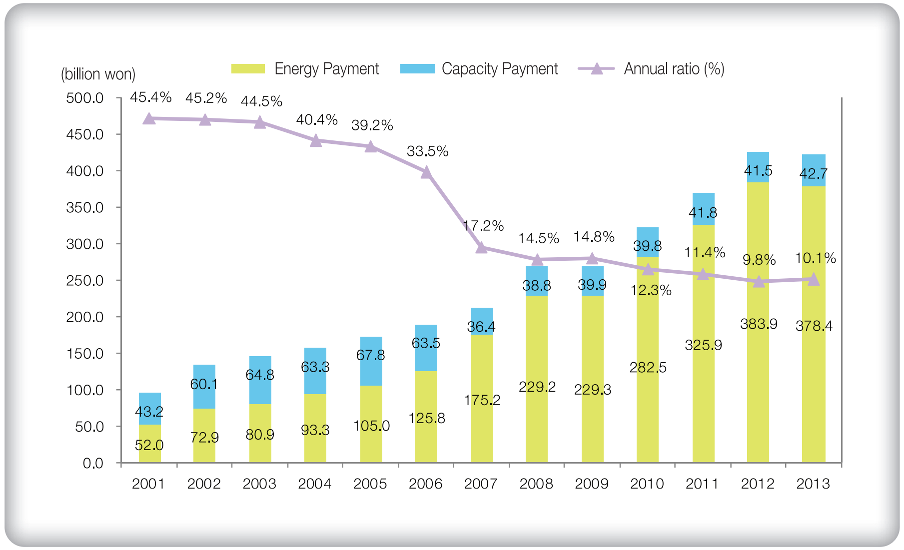
Classification		'03	'04	'05	'06	'07	'08	'09	'10	'11	'12	'13
Capacity payment (billion won)		64,806	63,311	67,773	63,470	36,412	38791	39,864	39,755	41,847	41,518	42,670
	ratio (%)	44.5	40.4	39.2	33.5	17.2	14.5	14.8	12.3	11.4	9.8	10.1
Energy payment (billion won)		80,935	93,256	105,035	125,775	175,160	229,207	229,254	282,489	325,937	383,879	378,939
	ratio (%)	55.5	59.6	60.8	66.5	82.8	85.5	85.2	87.7	88.6	90.2	89.9
Total payment (billion won)		145,741	156,568	172,808	189,245	211,572	267,999	269,118	322,243	367,784	425,397	421,062

These trends were driven by changed energy payment standards that shifted from the BLMP (about 19 won/kWh) to the RMP (nuclear 32.20 won, bituminous coal 32.68 won, and anthracite 38.52 won) and decreased capacity price for reference base load generators that fell from 21.49 won/kWh at the time of market opening to 7.46 won/kWh after a series of the following changes: the capacity payment unit cost for base load generators fell in 2004; the capacity price adjusted coefficient for base load generators was lowered in 2006; and the dual-capacity price for base load and non-base load power generators was unified in 2007. These trends continued in 2008, eventually converting much capacity payment for base load generators to energy payment. On the other hand, the SEP steadily increased in line with the rising trading volume until 2012. The SEP percentage in the total payment continued to go up until the same year.

18) Wolsong #1 in outage with the termination of design life since October 29, 2012; nuclear generators in outage for replacement of faulty parts (Shin-Kori #1 between April 8, 2013 and January 4, 2014; Shin-Kori #2 between May 29, 2013 and January 9, 2014; and Shin-Wolsong #1 between May 29, 2013 and January 4, 2014)

19) Energy payment above includes uplift payment.

The capacity payment (CP) ratio



The CP in 2013 steadily increased year on year. The CP percentage in the total payment also slightly went up. With no year-on-year change in the reference capacity price, the rise in installed capacity and the resulting rise in bid capacity are considered to be the major contributors. The 1.4% decrease in percentage of energy payment was one of the contributors as it was affected by the introduction of the Soft Price Cap[20], the reduction in adjustment factor for settlement, and the fall in fuel costs of LNG and oil. See the analysis on the uplift payment in the Market Competitiveness section of this report.

In addition, the capacity payment ratio of base load generators stayed around 85% between 2001 and 2003 and then was reduced to 82% in 2004, 62.8% in 2007, 61.9% in 2010 and 2011, and 59.5% in 2013. This drop was driven largely by a base load capacity price fall (1 won/kWh) in 2004, the lowered capacity-adjusted coefficient for base load generators in 2006 and unified capacity prices that brought reference capacity prices down by around 13 won/kWh in 2007. Of particular note, it was to decrease the capacity price of base load generators to the level of non-base load generators. This brought down the capacity payment ratio of base load generator to its composition ratio of installed capacity (on a market participation basis)[21] since 2007 and the trend continued in 2013.

Composition ratio of capacity payment by base load and non-base load generators

(Unit: %)

Classification	'03	'04	'05	'06	'07	'08	'09	'10	'11	'12	'13
Non-base load	15.8	17.4	17.2	19.6	37.2	37.1	36.4	36.8	38.1	38.1	40.5
Base load	84.2	82.6	82.8	80.4	62.8	62.9	63.6	63.2	61.9	61.9	59.5

However, the capacity payment ratio of non-base load generators has been on the increase due to repercussive effect from the decreased capacity payment of base load generators. Since then, however, the introduction of unified capacity pricing brought down the capacity payment ratio of base load generator to its composition ratio of installed capacity (on a market participation basis). In 2011 and 2012, there was no change in the capacity payment ratios of base load generators and non-base load generators. In 2013, however, the capacity payment ratio of base load generators increased. In our analysis, the rise results from the increase in installed capacity of non-base load generators with the entry of new LNG CC generators such as the units installed after Ulsan CC, Yulchon CC, and Bugok CC as well as Sejong Combined Heat and Power Plant

20) Taking effect in March 2013, the Soft Price Cap instead of market prices was applied to a number of settlements as the market prices exceeded the reference price cap all through the year in 2013.

21) Share of installed capacity of base load generators: 58% in 2009, 56% in 2010, 55% in 2011, 55% in 2012 and 53% in 2013.

Unit cost for capacity payment[22)]

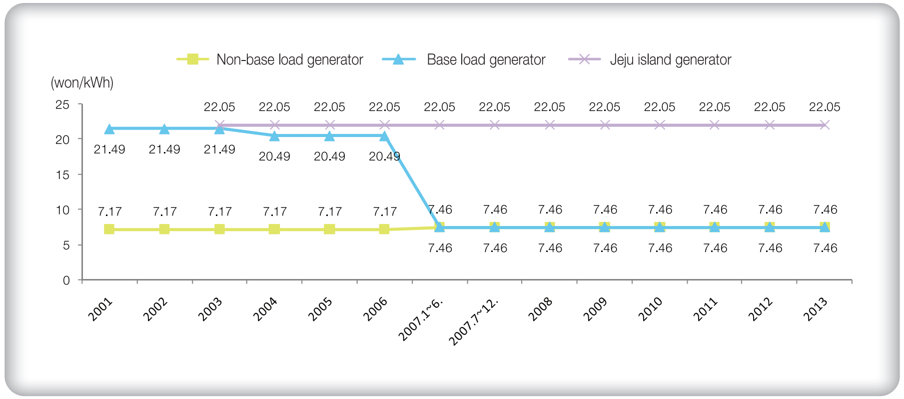
(Unit: won/kWh)

Classification	'03	'04	'05	'06	'07	'08	'09	'10	'11	'12	'13
Unit cost	16.68	15.67	15.63	14.15	7.93	7.89	7.78	7.67	7.75	7.83	7.91
Non-base load	7.61	7.61	7.61	7.70	8.26	8.45	8.16	8.03	8.12	8.25	8.17
Base load	21.49	20.17	20.00	17.77	7.74	7.59	7.58	7.48	7.53	7.59	7.74

The capacity payment unit cost remained at 14 - 16 won/kWh since 2001, standing at 7.91 won/kWh. However, it plunged to about half since 2007 as the reference capacity price for base load generators at 20.49 won/kWh decreased to the level of non-base load generators at 7.46 won/kWh, following the changes in the capacity price scheme. There has been no change in the reference capacity price, followed by no remarkable change in the unit cost remaining at 7 - 8 won/kWh.

Since 2007 when the reference capacity prices of capacity payment for non-base load generators and base load generators were unified, their capacity payment unit cost fell drastically. In 2013, the gap of the unit cost between non-base load generators and base load generators remained narrow at 0.43 won/kWh. With only the capacity payment considered, there are fewer incentives than before to increase the capacity of base load generators. As the energy payment for base load generators is now set by the market price[23)] rather than the RMP, however, private GenCos have more incentives to join the base load generator market. With the revision of the Electricity Market Rules in 2012, a new provision was put in place on the reasonable standard for setting the payment standard for base load generators operated by private GenGos to prevent them from making excessive profits over the KEPCO subsidiaries. With the changes in the capacity payment and energy payment schemes, private GenCos that own base load generators are now more likely to take into account actual operating ratios and market prices for a bid. Therefore, regular check up on bidding will be needed going forward. The chart below shows the reference capacity price trends since the market opening.

Reference capacity price



22) The capacity payment unit cost is calculated by dividing the capacity payment by availability.

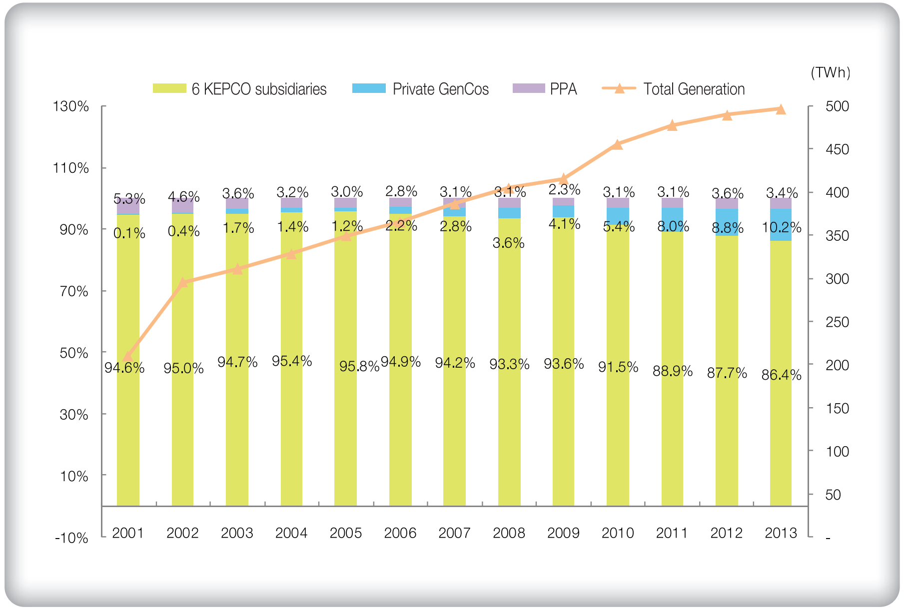
23) Power generators of GenCos with more than 50% of shares owned by electricity retailers that are subject to government rate regulation are paid according to the SMP adjusted coefficient.

Market Vitality

Generation Output by Private GenCos

The diagram above chronicles the amount of energy generated by the supply channel and shows energy trade of the six KEPCO subsidiaries and the private GenCos in the power market; PPA (Power Purchase Agreement)[24] and power markets where the six KEPCO subsidiaries and private GenCos trade their energy.

Generation output of Kepco subsidiaries and private GenCos



A total of 479,525 GWh was traded in the wholesale market in 2013, accounting for 96.6% of the total generation output in Korea. The share has been growing from 94.7% at the beginning of the market in 2001, hovering around 97% since 2004. Meanwhile, the generation output by PPA slightly decreased compared with that in 2001 at the time of electricity market opening. That is because the transmission loss factor[25] began to be applied and in recent years the availability of PPAs[26] rose because of the decreasing level of reserve margin. In our analysis, the installed capacity of PPAs remained almost the same while the generation capacity joining the electricity market has been on the increase, resulting in the low share of the generation output by PPAs. This landscape demonstrates the active trading status of the electricity market.

Supply ratio by electricity market and private GenCos

Classification	'02	'03	'04	'05	'06	'07	'08	'09	'10	'11	'12	'13
Electricity supplied by the market (Compared to the total amount of generated energy, %)	95.4	96.4	96.8	97.0	97.2	96.9	96.9	97.7	96.9	96.9	96.4	96.6
Electricity supplied by private GenCos (Compared to the total amount traded in the market, %)	0.4	1.8	1.5	1.3	2.3	2.8	3.7	4.2	5.5	8.3	9.1	10.6

24) The PPA refers to the amount of power traded by purchase agreements between KEPCO and private power-companies before the generation sector was divided up.

25) Section 2.5.5 of the Electricity Market Rules stipulates that the transmission loss factor shall be reflected 100% from 2016 and beyond by increasing the portion 10%p every year starting from 10% in 2007.

26) See the Generation Information System for the availability status of major PPAs.

* A: (2005) 16.7% → (2009) 19.6% → (2013) 39.4%
* B: (2005) 36.3% → (2009) 40.2% → (2013) 51.6%
* C: (2005) 36.4% → (2009) 33.4% → (2013) 66.6%

The generation output by private GenCos rose up significantly since the establishment of the electricity market to 50,810 GWh in 2013. That number is a 47-time increase compared with that of 2002 and accounts for 10.6% of the total generation output in the electricity market. In particular, the generation output by the six KEPCO subsidiaries grew 1.6% while that by the private GenCos grew 18.1%. A significant contributor to the dramatic increase is the increasing entry of private GenCos such as SK E&S and GS EPS as well as the construction of additional units[27]. Another large contributor was the rise in operating hours of the private GenCos as the operating reserve was low in the market in 2012 because of the long outage period of nuclear generators. As of December 2013, with the increasing number of new renewable energy GenCos[28] by the aid of governmental policy for new renewable energy, the number of GenCos trading in the electricity market dramatically increased to a total of 540[29].

The generation output by PPA has decreased while that of private GenCos has been on the increase until now since the establishment of the electricity market. Such development shows active electricity trading and it is a positive sign of market vitality.

Market Competitiveness

Uplift

Electricity companies could be tempted to exercise market power to gain uplift by using the high variable costs of must-run units and taking advantage of transmission congestion to change operation times. As a matter of fact, this practice has been prevalent in the markets of the developed countries that have adopted zonal pricing. Also, the recent market improvement measures and increased portion of energy trading payments in the settlement amounts due to the rise in power demand and fuel prices have made the actual generation rate of the power generators a profit-determining factor for electricity companies. Therefore, if there are system operational limits such as transmission congestion, power generators that produce energy without following the merit order of the market need to be regulated to the level where only their generation cost is compensated.

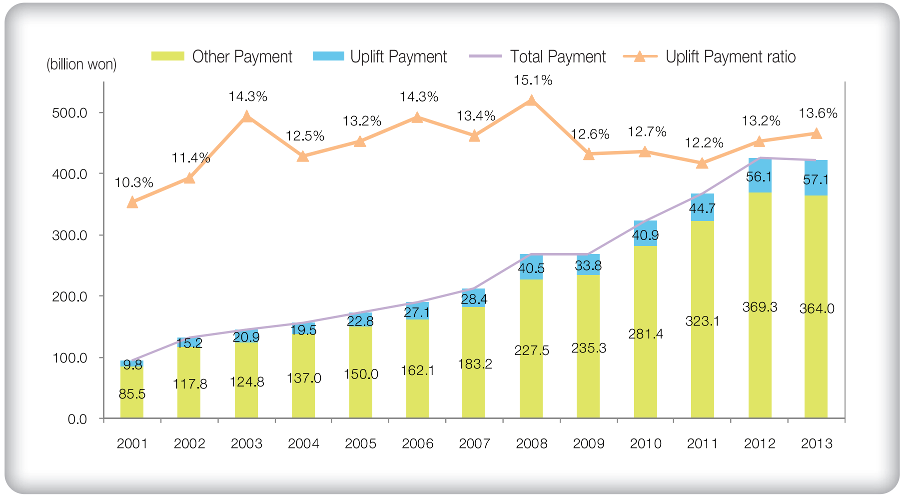
Therefore, the cost of transmission congestion and must-run units needs to be identified and managed. The changes of uplift indirectly reflect the degree to which it affected the competition as well as the efficiency of the system operation such as with ancillary services, CON and COFF generation[30] and the generation of the commissioning unit.

The chart below shows the annual ratio of uplift in the total market settlement. The ratio of uplift in the total settlement has been around 10%-15% since the establishment of the electricity market.

27) Installed capacity by private GenCos in the electricity market: 3.1% in 2002 → 20.3% in 2013
28) The installed capacity of new renewable energy generators increased with the rising annual quota as per RPS.
29) As the end of December 2013, there are 540 members in the electricity market of which 539 are GenCos and one is KEPCO(transmission, distribution and sales company).

30) This consists of GSCON, SCON, COFF and so on. GSCON is generated by heat supply, fuel constraints, commissioning, diverse tests and other factors that GenCos required. SCON is generated by the system frequency & voltage control, underestimation of power demand, pump load and other factors. COFF is generated by an overestimation of demand, an acquisition of reserve margin and other factors.

Uplift ratio



The uplift ratio in 2003 and 2006 was relatively high at 14.3% as it was in 2003 when the generation cost for replacing the unstable LNG supply with alternative fuel (diesel) was compensated for in the settlement. Also, in 2006, the settlement was influenced by the following: the changed calculation formula[31] that was used in recovering the actual fuel cost of reference base load generators[32] since 2005; the increased CON and COFF as oil generators were operated on a preferential basis due to a lack of LNG; and increased energy produced before commercial operations. In 2008, the uplift ratio went up as fuel costs rose up and the availability of pumped-storage generators increased. Turning in 2009, however, the uplift decreased year on year as constrained-on or constrained-off energy settlement associated with a fall in the annual fuel price decreased and the energy produced before commercial operations sharply decreased. Since 2009, the uplift payment and its ratio have been on the increase. In 2012, the growth rate of constrained-on energy payment (CON) was high due to the rise in fuel costs and the surge in energy produced for system constraints of oil generators.

The uplift settlement ratio stood at 13.6%[33] in 2013, a 0.4%p year-on-year increase. The uplift payment amounted to 5.7 trillion won, 1.7% up from 2012. In our analysis, this was mainly affected by the constrained-on and constrained-off energy payment, which account for a majority of the uplift payment, increased 2.0% year on year. Compared with the year 2012, the amount of constrained-on and constrained-off energy increased 9.4% while their payment increased modestly. In our analysis, that is because the fuel costs of major fuel types such as LNG and oil went down. The constrained generation output of LNG increased remarkably and as a result its payment increased. Meanwhile, the ratio of constrained generation output by oil decreased and its fuel cost sharply decreased, reducing the constrained payment. The up and down affected the entire uplift payment in our analysis.

31) Difference between actual fuel-cost applied-settlement and standard fuel-cost applied-settlement was additionally paid as uplift in order to reflect actual fuel costs to the reference base load generators.
32) The reference base load generator refers to the base load generator whose actual fuel cost is higher than the standard fuel cost.
33) The average price for uplift payment (uplift payment/total trading volume) remained the same at 11.90 won/kWh as that of the year 2012.

Power System Status

Electric-Power Supply Stability

Capacity Reserve Margin

Maintaining efficiency and stability of the system operation are very important in the electricity market. The electricity market must always reserve a certain amount of backup power that exceeds the power demand for a contingencies such as blackouts that may cause huge social costs.

Since the establishment of the electricity market, the capacity reserve margin at the peak demand point of the year was maintained at 13% - 18% (capacity reserve margin of 5,000 MW - 8,000 MW) between 2001 - 2005 but it has fallen to one-digit level since 2006, disrupting the supply-demand stability. That is mainly because the peak demand growth rates between 2004 and 2007 were higher than the installed capacity growth rates with the higher-than-expected temperatures and the remarkably increased cooling load. In 2007, the capacity margin stood at 7.9%. Turning in 2008, the installed capacity increased with construction of Youngheung #3 & #4 and Boryeong #7 & #8 while the peak demand increased only 0.8% because of the economic downturn, returning the capacity margin to 12.0% temporarily. In 2009, the annual average power demand increased slowly. In winter of the year, the demand increased 6.4% from the previous year to 66,797 MW, which is a record high of the peak demand and the capacity reserve fell to below 10%. That was because of the economic recovery in the second half and the cold weather. And in 2010, the growth rate of electric-power peak demand from 2009 amounted to 6.8%, but the growth rate of the generation facilities did not catch up with the growth rate of the peak demand, leading to the capacity reserve margin at 6.7%. The trend continued in 2011. The peak demand occurred in winter, leading to the lowest capacity reserve margin at 4.1%. since the establishment of the electricity market. In winter 2012, the peak demand increased 3.9% from the previous year to 75,987 MW. New construction of generating facilities increased beyond the demand growth rate. In the same year, the installed capacity growth rate was 7.5% and the capacity reserve turned around, increasing 3.6%p year on year to 7.7%.

Power supply & demand outlook

(Unit: MW, %)

Classifi-cation	Actual[34]							Plan[35]		
	2007	2008	2009	2010	2011	2012	**2013**	2014	2020	2027
Capacity	67,196	70,353	73,310	76,078	76,131	81,806	**82,296**	94,192	124,433	130,495
Peak demand	62,285	62,794	66,797	71,308	73,137	75,987	**76,522**	80,969	95,316	110,886
Capacity Reserve Margin (percent)	4,911 (7.9)	7,559 (12.0)	6,513 (9.8)	4,770 (6.7)	2,994 (4.1)	5,819 (7.7)	**5,774 (7.5)**	13,223 (16.3)	29,117 (30.5)	19,609 (17.7)

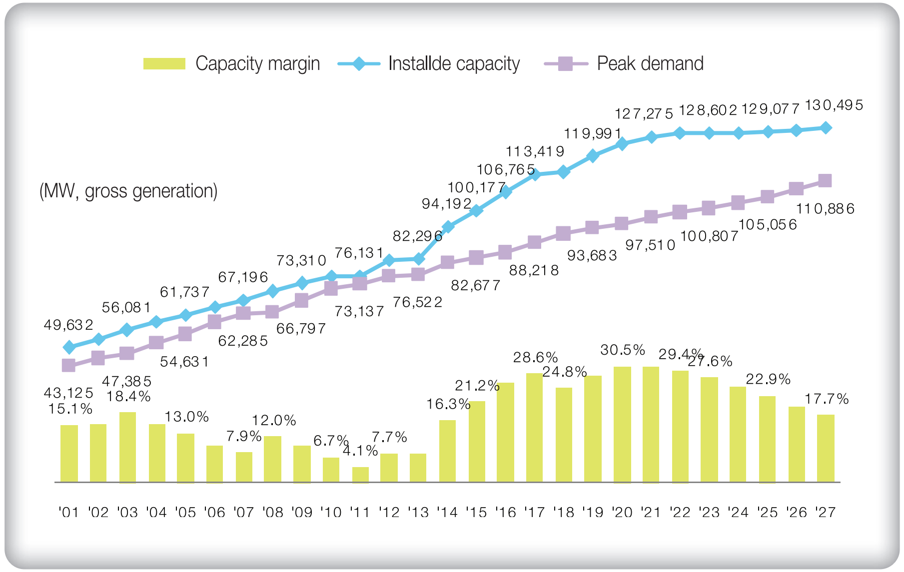
The peak demand in 2013 increased 0.7% year on year to 76,522 MW on January 3. With the operating capacity of 80,713 MW, the supply reserve reached 4,191 MW of which percentage was 5.5%. The installed capacity was 82,296 MW and the capacity reserve margin was 7.5%. Turning in the second half of 2013, both the installed capacity and the operating capacity went up together with the construction of additional units at Yulchon CC, Pyeongtaek CC, Ulsan CC, Bugok CC and Sejong Combined Heat and

34) The performance data is based on the data as of the day with peak demand of the corresponding year.
35) See the 6th Basic Plan of Long-Term Electricity Supply and Demand (Announcement by the Ministry of Knowledge Economy in February 2013).

Power Plant. The supply and demand became stabilized. The installed capacity increased to 86,177 MW as of late 2013 and indeed no power shortage alert was issued after September 2013.

Due to the insufficient reserve in 2013, a total of 38 alert issued in 2013 and the last notice was issued in August of the year. The number of issues decreased compared with 75 times in 2012. In more detail, the issues include 34 prepared level notices for the supply reserve at 4,000 MW - 5,000 MW, 4 attentive level notices for the operating reserve at 3,000 MW - 4,000 MW and no cautious level notice was issued for the operating reserve at 2,000 MW - 3,000 MW.

Power supply and demand by year



The chart above shows the outlook for peak demand, generation capacity and capacity margin in the 6th Basic Plan of Long-Term Electricity Supply and Demand for the years between 2014 and 2027 (February 2013)[36]. In the 6th plan, the target reserve margin is 22% by the year 2027 considering the minimum capacity margin and uncertainty in demand for possible generator failures in order to meet the future economic needs and obtain generation facilities.

Progressive measures such as the demand management program, use of commissioning generators, or postponing the schedule for removal of generation facilities or for the planned overhaul during a short period may probably be required to cover the capacity reserve margin that is predicted to be relatively low until summer 2014. However, after that, the supply stability is expected to improve as the capacity margin from winter 2014 is forecast to be in the range of 16% - 30%.

The expected long-term supply stability is closely linked to the return on generation investment. The current system of paying the variable cost by the marginal price and capacity payment encourages GenCos to build more power plants. The "Surveys on Gencos' intents for construction" conducted for the 6th Basic Plan (February 2013) to gauge the companies' intents to join the market found that the GenCos were willing to build new units for 77,405 MW of electricity, including 23 private GenCos for 57,265 MW at 63 new units between 2013 and 2027. The result signifies their aggressiveness in facility investment.

Recently in Korea, the power demand has been high compared with the size of generation facilities because of the energy-intensive industrial structure and the relatively lower electric rates than other energy prices. It is necessary to reduce power demand by rationalizing the rate structures and streamlining the pricing scheme although it is not easy to cut power demand in the current industrial structure in Korea in a short period of time. Generation facilities should be put in place considering the size of the national economy based on the reliable demand forecast.

36) The long-term outlook referenced to the target peak demand and the seasonal installed capacity with peak demand under the 6th Basic Plan of Long-Term Electricity Supply and Demand (Announcement by the Ministry of Knowledge Economy in February 2013) as of winter 2014 and 2015, and as of summer 2016 and beyond.

Transmission Network Constraints

Transmission Facilities Expansion Plan

The current electric-power system is characterized by regional differences in demand because of the high population density in the Seoul metropolitan areas and the large industrial complex formed in Ulsan and Yeosu as well as the power demand constantly on the increase. There are operating difficulties caused by fault current or transient stability issues in many congested areas, and they sometimes cause many constraints in operating generation facilities.

Therefore, the construction of transmission and transformation facilities are of the same importance with generator construction plans. Timely facility expansion in the major congested areas is needed to prevent the emergence of local market powers as well as to minimize the congestion cost from the economic perspective.

However, as more and more people become environmentally aware, residential opposition to facility construction has delayed and even canceled the scheduled expansion, raising uncertainties about the construction plans. Hence, a mid-long term review on the status and the plans for transmission expansion should be carried out to break the current deadlock.

Transmission facilities expansion

(Unit: C-km)

Classi-fication	Actual					
	2008	2009	2010	2011	2012	2013
765kV	755	755	835	835	835	835
345kV	8,310	8,552	8,580	8,653	8,770	9,005
154kV	20,298	20,469	20,777	21,280	21,577	21,976
Sum	29,363	29,776	30,192	30,768	31,182	31,816

Transformation facilities expansion

(Unit: 10 MVA)

Classi-fication	Actual					
	2008	2009	2010	2011	2012	2013
765kV	2,311	2,411	2,712	2,912	2,912	3,112
345kV	9,888	10,460	10,810	11,160	11,560	11,710
154kV	11,481	11,864	12,068	12,323	12,614	13,093
Sum	23,680	24,735	25,590	26,395	27,086	27,915

The capacity of transmission facilities in 2013 stood at 31,816 C-km, a 2.0% increase from the previous year beyond the annual average of 1.3% recorded in recent five years between 2008 and 2012. Also, the capacity of transformation facilities stood at 27,915 kVA, a 3.1% increase from the previous year below the annual average of 3.5% during the same five year period. KEPCO announced its long-term plan for transmission and distribution facilities in August 2013. The plan describes the mid-to-long-term plan for expansion of power transmission and transformation facilities including the solution for synchronization of new generators included in the 6th supply and demand plan and the measures to enhance reliability in the electric-power system.

Meeting the power demand in the Seoul metropolitan areas in short of supply depends on the appropriate construction of power generation, transmission and transformation facilities. The table below shows the Power supply and demand outlook for the Seoul metropolitan areas.

Power supply and demand in the Seoul metropolitan areas

(Unit: MW, %)

Classi-fication	Actual[37]				Plan[38]		
	2010	2011	2012	2013	2014	2020	2027
Generating capacity in the area	17,426	18,710	19,986	20,352	27,577	33,851	30,679
Transmission credit	12,500	12,700	12,000	12,000	14,827	19,528	20,948
Total capacity	29,926	31,410	31,986	32,352	42,404	53,379	51,627
Peak demand	28,368	29,614	30,369	30,503	32,062	34,859	37,186
Installed reserve (margin)[39]	1,558(5.5)	1,796(6.1)	1,617(5.3)	1,849(6.1)	10,345(32.3)	18,520(53.1)	14,441(38.8)

The peak demand in the Seoul metropolitan areas in 2013 increased 0.4% year on year to 30,503 MW. The power interchange capability limit for the Seoul metropolitan areas remained the same at 12,000 MW as the previous year. The generation capacity in the Seoul metropolitan areas increased 1.8% to 20,352 MW with the construction of Incheon CC #3. The total capacity for supply in the Seoul metropolitan areas in 2013 increased 1.4% year on year to 32,352 MW. The reserve margin stood at 6.1%, 0.7%p up from 2012.

However, the annual average peak demand and power intersupply to the Seoul metropolitan areas are expected to go up each steadily during this period (2014 - 2027). Therefore, further expansion of 765kV and 345kV transmission and transformation facilities is needed to brace for the expected rise in demand and the power interchange in the Seoul metropolitan areas during the same period. Also, generation facilities need to be expanded for the same purposes.

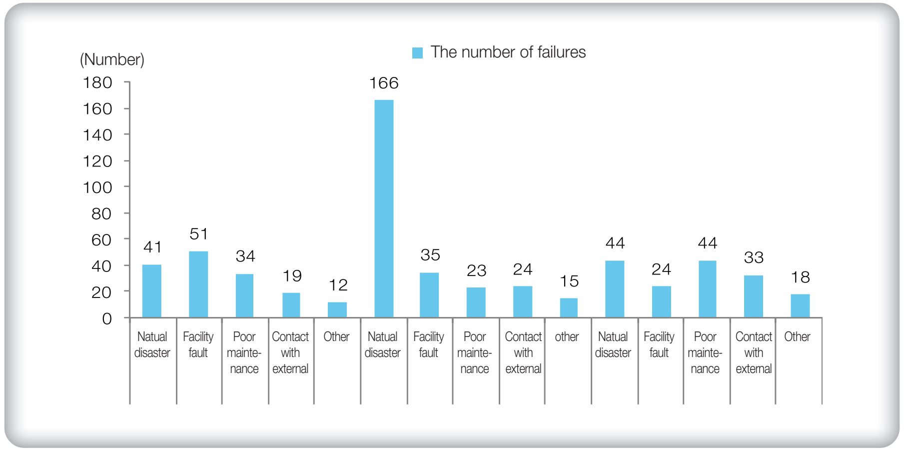
37) A peak demand record high was in the winter between 2010 and 2013. In 2013, the peak demand took place in January.
38) See the 6th Basic Plan of Long-Term Electricity Supply and Demand (Announcement by the Ministry of Knowledge Economy in February 2013).
39) The forecast capacity and reserve in the plan refer to the installed capacity and the capacity reserve margin respectively.

Transmission and Transformation Facility Failures

It is important to examine the failure records of the transmission and transformation facilities because it directly affects the electricity supply reliability and transmission congestion.

In 2013, there were 163 failures[40] of transmission and transformation facilities (transmission facilities: 93, transformation facilities: 70), a decrease of 100 cases from 263 cases in 2012. The number of failure cases of transmission facilities decreased by 104 from 2012; transformation facilities' increased by four. The number of transmission facility line failures decreased and it affected the decrease in the number of all failures in the transmission and transformation facilities. The number of failures caused by natural disasters such as typhoon and snowstorm sharply decreased in the transmission facilities and it affected the overall sharp decrease in the number of failures in the same facilities.

Transmission and transformation facility failures by cause



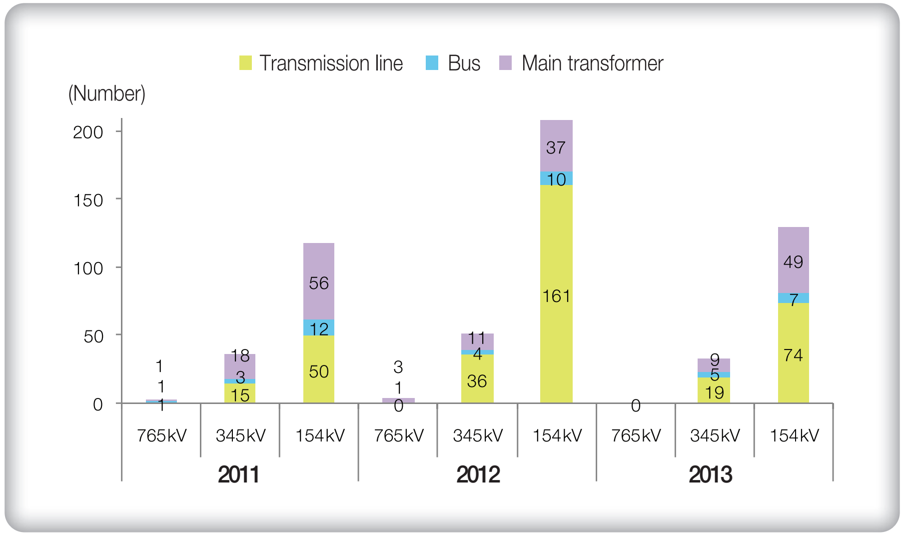
40) See the 2013 statistics on power facility failures released by KPX.

A majority of the failures of transmission and transformation facilities in 2013 included 44 cases of natural disasters and poor maintenance. Following natural disasters and poor maintenance, the main causes included 33 cases of contact with externals, 24 facility defect cases, and 18 other cases. Contacts with externals were mainly contacts with cranes, trees and animals. In 2012, a majority of failure cases were caused by natural disasters such as thundering and rainstorm. In 2013, no large typhoon like Bolaven or snowstorm hit Korea and as a result the number of failures caused by natural disasters decreased significantly.

In 2013, there were no failure cases in the 765kV transmission lines (the same from the previous year) and transformation facilities (down 4 cases) from 2012. There were 33 failure cases in the 345kV facility failures (down 17 cases in the transmission lines and down one in the transformation facilities from 2012). There were 130 failure cases in the 154kV facilities (down 87 cases in the transmission lines and up nine cases in the transformation facilities from 2011). The number of failure cases in the 154kV facilities decreased remarkably, but it accounted for 80% out of the total failure cases by voltage as it did in 2012. That is because there are much more 154kV facilities than 345kV facilities. By facility in terms of the frequency in the failures, transmission lines accounted for 57%, main transformers 36% and bus 7%, which shows that the more exposed to nature a facility is, the higher the percentage is.

In 2013, there were 238 failures of generation facilities, 42 up from the previous year. The six KEPCO subsidiaries saw 105 failure cases and the private GenCos saw 133 failure cases each. In particular, the private GenCos saw 35 more failures than the previous year, which is a significant increase. Looking into their failures by fuel type at the six KEPCO subsidiaries, a total of 105 failure cases include: nuclear (6), bituminous coal & anthracite coal (29), LNG (63), hydro & pumped-storage (4) and oil (9). LNG generators ranked the most drastic rise among the fuel types, up 13 from the previous year. In our analysis, the numbers of failure cases by both private GenCos and LNG generators increased due to the additional installation of 14 LNG generators and 45 more failure cases in the generator type. Looking into the statistics by cause, there were 131 poor maintenance and 85 facility defects. The two causes accounted for 90.8% of the total. Contact with externals caused two cases and others caused 15 cases.

Transmission and transformation facility failure by voltage



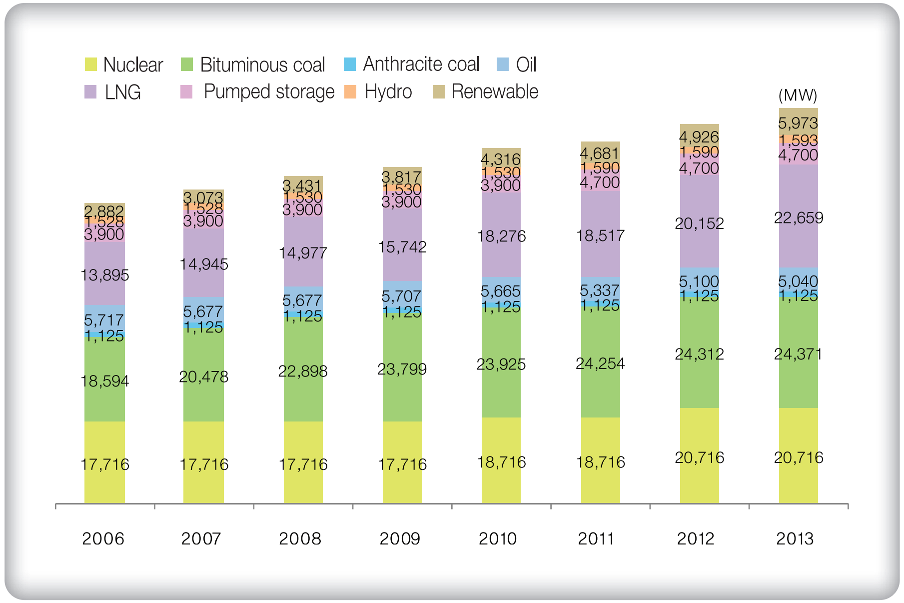
Market Structure

Changes in Installed Capacity

Changes in Installed Capacity Classified by Fuel Type

Installed capacity classified by fuel type has a direct impact not only on the power supply and demand but also on the price and supply curve in the market. The chart below shows the annual installed capacity by fuel type that registered as members in the market.

Installed capacity by fuel type



The total installed capacity in 2013 increased 4.3% from 2012 to 86,177 MW. The growth rate in 2013 was 4.3%[41] because of many constructions of LNG CC generators while the rate stood at 4.7% in 2012 because of additional construction of large nuclear facilities.

By fuel type, the number of new renewable energy generators increased 21.3%, the most significant rise among the fuel types. The remarkable increase was due to many installations of photovoltaic and wind power generators. In the first place, the government promoted development and deployment of new renewable energy[42] despite the constraints in local requirements and operating ratio of the generators. The LNG generators also increased 12.4% with the new construction of additional units at existing CC plants such as Pyeongtaek #5 & #6 GT and Yulchon #3 & #4 GT as well as Sejong Combined Heat and Power Plant[43]. Only the oil generators decreased 4.4% in 2012, and they decreased 1.2% in 2013 with the shutdown of Namjeju D/P and the conversion into non-centrally dispatched generators at Sihwa Combined Heat and Power Plant. The oil generators have been on the decrease since 2009.

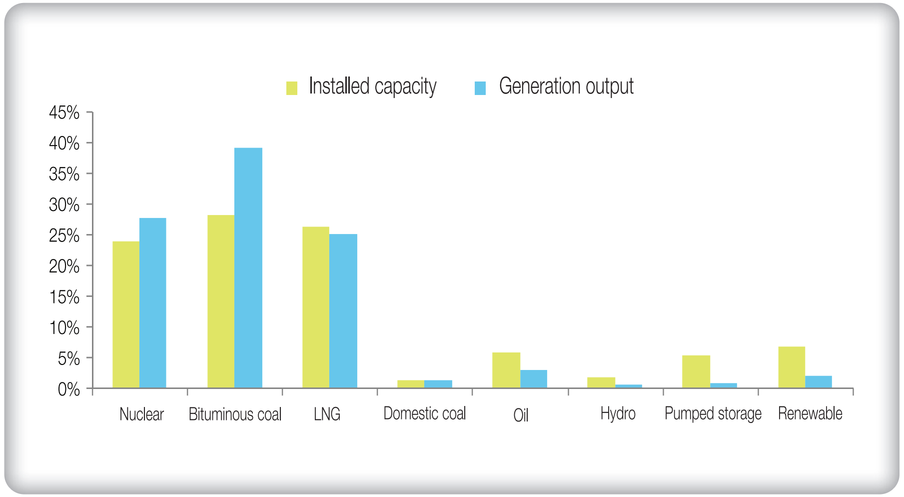
As shown in the following chart on the installed capacity and the generation output by fuel type in 2013, bituminous coal, nuclear power and LNG took the majority shares in the generation output as well as in the installed capacity.

41) The total installed capacity in 2013 increased 4.3% year on year to 86,177 MW from 82,621 MW in 2012 (as of late 2012 and 2013).

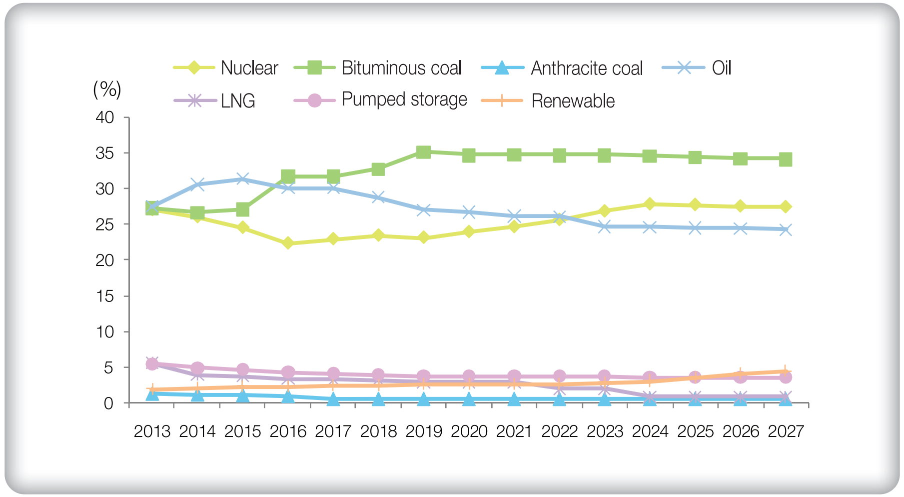
42) In compliance with the Act on the promotion of the development, use and diffusion of the new and renewable energy, the Renewable Portfolio Standard (RPS) has been put in place since January 2012 following the Feed in Tariff (FIT). As the RPS commitment has been on the increase every year, more and more small-sized new renewable energy GenCos entered the electricity market in anticipation of making profits from the trade of Renewable Energy Certificates (RECs).

43) In 2013, some LNG CC generators joined the electricity market, including Incheon CC #3 (January, 450 MW), Ohsung CC (March, 770 MW), Soowan Combined Heat and Power Plant (March, 115 MW), Yulchon CC #3 & #4 GT (June, 572 MW), Ulsan CC #7 & #8 GT (July, 486 MW), Byeollae CC (July, 115 MW), Pyeongtaek CC #5 & #6 GT (July, 484 MW), Bugok CC #3 (August, 382 MW), and Sejong Combined Heat and Power Plant (November, 530 MW).

Installed capacity and generation output by fuel type (2013)



Energy mix forecast by fuel type



The generation output and the installed capacity stand at a similar level. However, the generation output percentage is higher than the installed capacity percentage in the base load generators such as nuclear generators and bituminous coal generators while the installed capacity percentage is higher than the generation output percentage in the LNG generators and oil generators. In 2013, the installed capacity and generation output shares by fuel type were within 1% deviation, showing a similar pattern with that of 2012. The diagram below is the prospective energy portfolio from each fuel type[44].

44) The energy mix forecast is based on the 6th Basic Plan of Long-Term Electricity Supply and Demand (Announcement by the Ministry of Knowledge Economy in February 2013) was referenced and some of the revisions of the Plan were not included in the forecast.

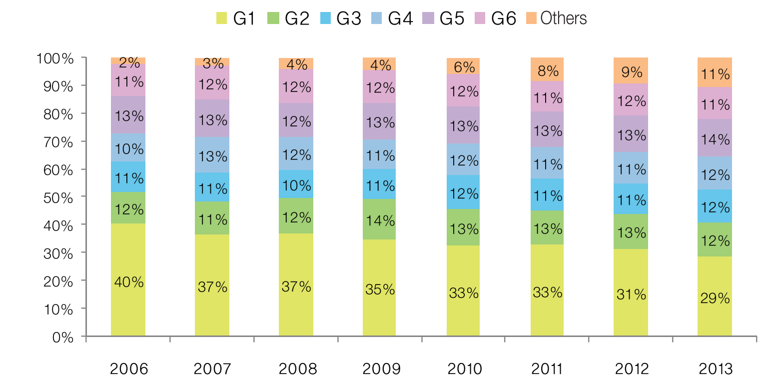
Market Share

Market Share on Trading Volume by Major GenCos

By the very nature of electricity, it is not easy to build generators in a short period let alone storing the electricity while its demand is non-elastic. If only a few GenCos exercise market power in the electricity market, they may cause market inefficiency and raise production costs and prices, giving the wrong investment signals. The market share index is the easiest and the most basic standard on which to gauge the market power of the participants. For example, a GenCo with a large market share may be tempted to raise the market price by withholding its generating capacity or exaggerating its marginal costs. In order to prevent GenCos from exploiting their market power; their shares based on trading volume need to be closely monitored to keep track of their potential to exploit their market power[45). The market shares can be seen through the trading index.

The trading shares by the major GenCos over the last six years have changed only within a range of ±3%p. The GenCos' installed capacities by fuel type have increased evenly with the increasing trends in power demand and fuel prices.

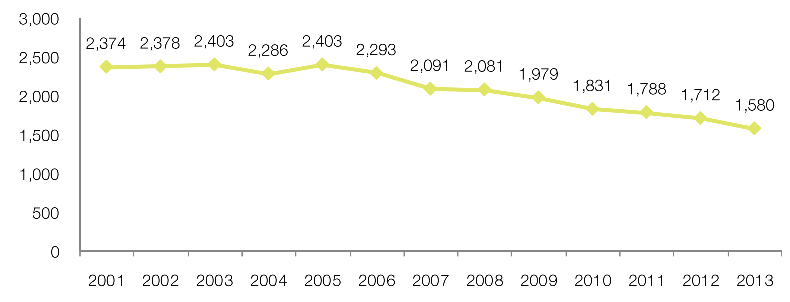
Trading share by major GenCos



The market concentration has been mitigated as the shares of the top three GenCos decreased to 55% in 2013 from 65% in 2006. This trend is mainly due to the new entries of private GenCos into the market. Not only new renewable energy (wind and photovoltaic) but also new private LNG facilities such as Yulchon CC #3 & #4 GT (June 2013, 572 MW) and Bugok CC #3 (August 2013, 382 MW) also played a significant role in weakening the market concentration. Another contributor is the falling market shares of the GenCos that own many nuclear or coal-fired base load generators (G1, G2 and G6) that operate at a certain level all through the year, contrary to the LNG and oil generators with the rising market shares following the increasing demand. The Herfindal-Hirschman Index (HHI) below also shows such a trend like above. The index was calculated based on the yearly power trading volume by GenCo.

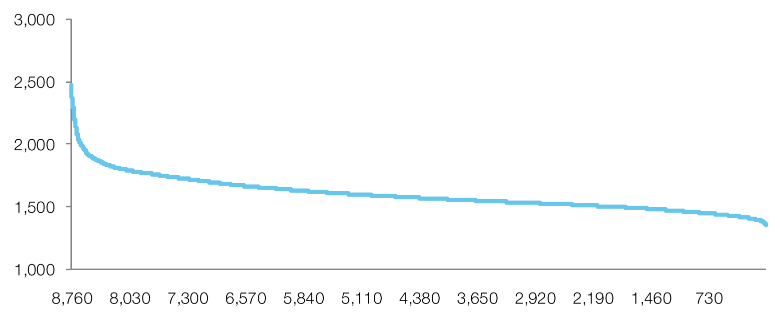
45) The index has several limits such as overlooking the flexible supply reserve, assuming the size of GenCos to be the same and failing to consider consumer and supply elasticity.

Trading share-based HHI by year



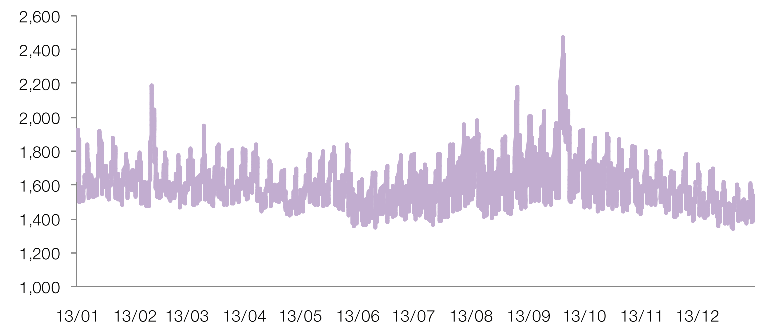
The HHI decreased 132 year on year down to 1,580. In the early period since the market opening, the HHI was around 2,500, which is considered highly concentrated. The HHI at 1,580 in 2013 is considered moderately concentrated in our analysis[46].

Annual trading volume based HHI by hour (on the scale basis)



The HHI based on trading volume by hour in 2013 was not over 2,500 and it is considered moderately concentrated. The HHI goes up mainly during the especially low load period because of the increasing percentage of base load generators. In 2012, for example, the HHI over 2,500 accounted for 0.8% during the especially low load period of the Korean Thanksgiving Day holidays. On the other hand, the HHI in 2013 was not over 2,500 even during the especially low load period, mitigating market concentration.

Annual trading volume based HHI by hour (on the time basis)



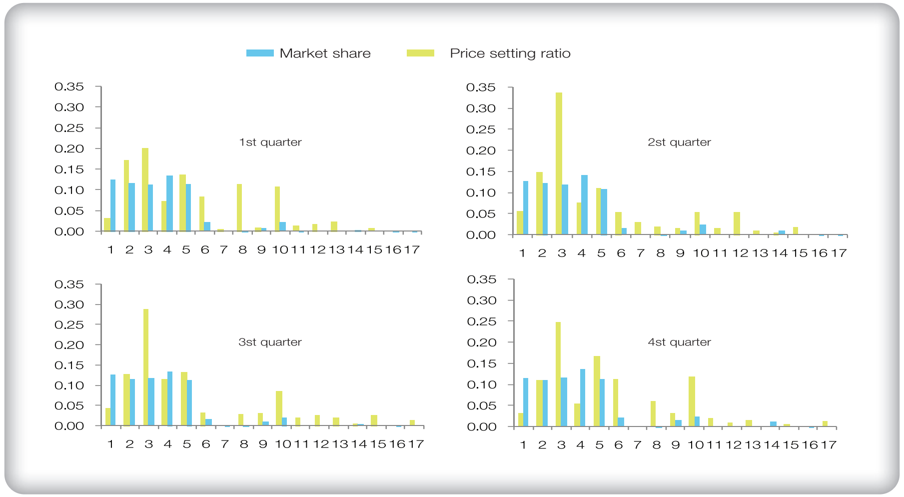
46) According to the recent U.S. Horizontal Merger Guidelines by the Department of Justice and the Fair Trading Commission released on August 19, 2010, the scales for the HHI-based concentration are as follows: HHI 〈 1500 (not concentrated), 1500 ≤ HHI ≤ 2500 (moderately concentrated), and HHI 〉 2500 (highly concentrated).

Market Price and Market Share of Price Deciding Marginal Firms

As market power can be exercised more frequently by each company rather than by the whole market, market power analysis needs to be carried out on each company, especially on marginal firms. Marginal firms refer to a company that can set prices. However, in Korean CBPs where costs are pre-evaluated unlike other power markets on bid prices by GenCos, a company's market power cannot be accurately measured by the number of times the company sets the price. The market share of each company is calculated based on its power generation output.

The chart below shows the market share of each marginal firm and its price-setting times by quarter. Here, the market shares were calculated based on the generation output on the 17 firms with high price-setting ratio. The implication is that the number of times and market share do not always have a positive correlation as a firm with higher price-setting ratio does not record a high market share. The market shares of the KEPCO subsidiaries remained within 12% ±2% whereas their price setting ratios were distributed widely among them. Our analysis is that there is low correlation between the price- setting ratios and the market shares.

Price-setting ratio and market share by major marginal firms

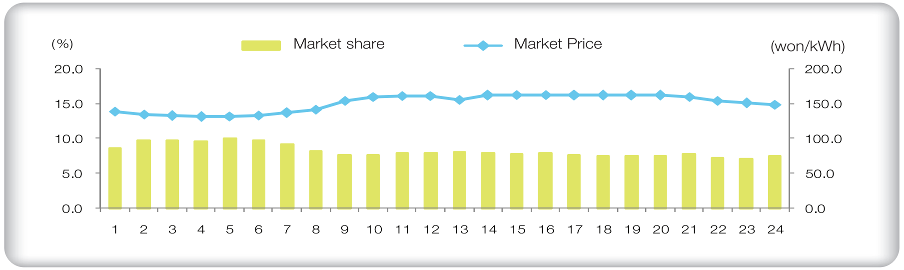


Looking into the market shares and prices of marginal firms, GenCos with high market shares (i.e., six subsidiaries of KEPCO that own low-price base load generators) tend to set the price during the hours of low market prices. On the other hand, producers with low market shares have more influence in setting the price during the hours of high market prices. The average of market shares and market prices[47] in the diagram below well demonstrate the correlation between 2011 and 2013.

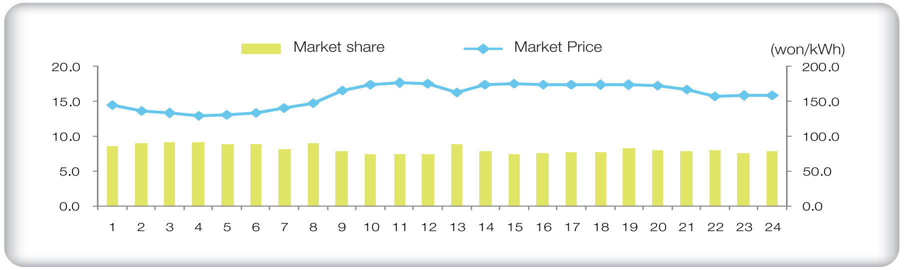
As described earlier, marginal firms are less likely to exercise strong market power as there is no price-based bid in the Korean electricity market. But, generally power demand tends to be low in time of low market prices. During the hours, therefore, the market-leading company may possibly exercise its market power by using capacity withdrawal and raise the market price. Therefore, we need to monitor it steadily in various aspects.

47) With the introduction of zonal pricing in 2010, the market share and the annual average prices of the marginal firms have been analyzed based on in-land figures.

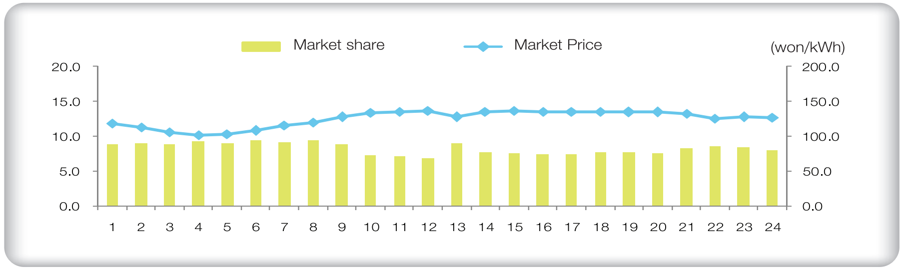
Marginal firms' market share and average market-price (2013)



Marginal firms' market share and average market-price (2012)



Marginal firms' market share and average market-price (2011)



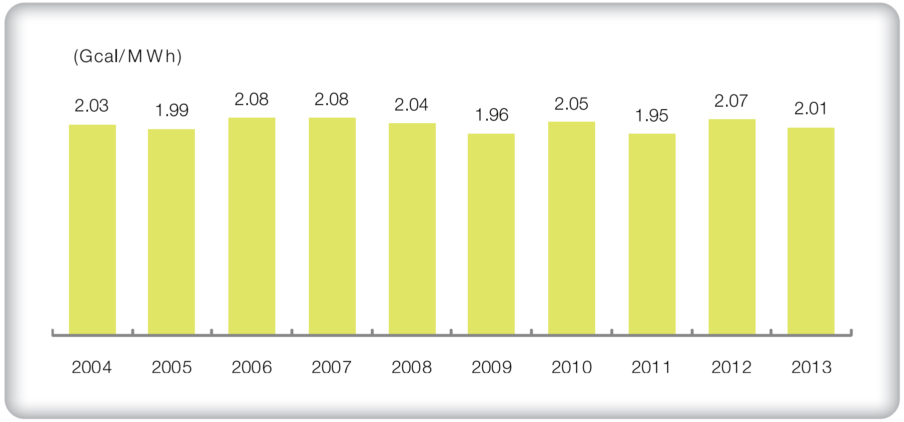
Market Performance

Market Supply Efficiency

Market Heat-Rate

Since the market heat-rate (MHR) refers to the amount of thermal energy needed to supply a unit of electricity (1 MWh) through the wholesale electricity market, it can be used to gauge the supply efficiency of the market. The chart below shows the heat-rate over the recent 10 years drawn by dividing the annual average market price into the annual average fuel cost[48] in order to analyze the supply market efficiency over the same period.

Market Heat-Rate

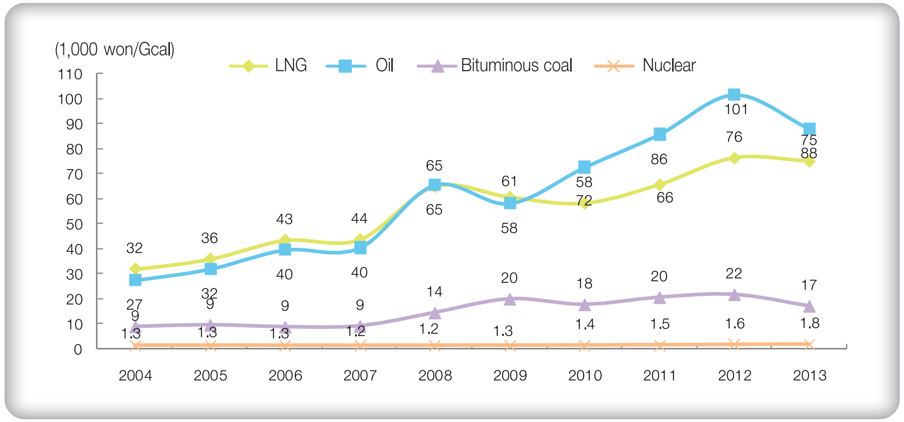


48) The annual average fuel cost is weighted-averaged by multiplying the fuel-cost by the fuel-type and annual price setting percentage by fuel-type.

In 2012, the fuel price increased 19.7% from 2011 while the market price rose up by 27.0%, raising the market heat rate higher than that of the previous year. The annual average operating hours percentage of nuclear generators decreased sharply with the long outage period caused by generator failures at large nuclear power plants such as Kori #1 and Yonggwang #5 & #6. In the meantime, the operating hours and price-setting ratios of generators with high variable cost increased along with the rising power demand. These factors accelerated the effect of the rise in fuel prices and in turn reduced market efficiency in our analysis.

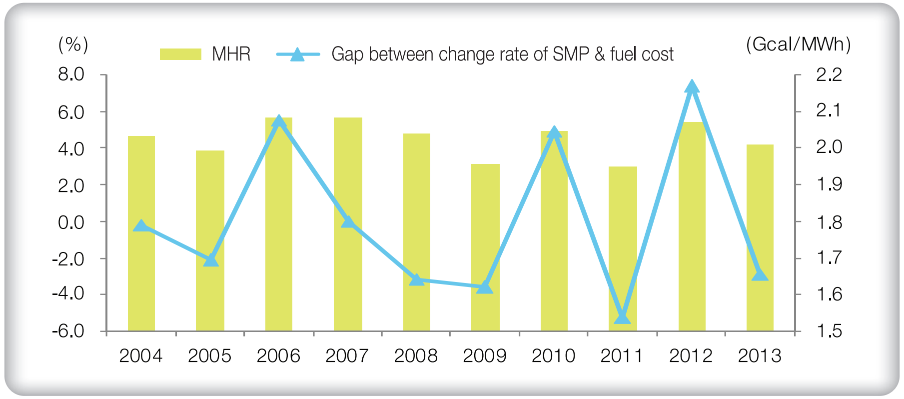
In 2013, the fuel price increased 2.5% from 2012 while the market price fell 5.4%, leading to the decreased market heat rate of 2.01 Gcal/MWh from 2.07 Gcal/MWh in 2012. The market price in 2013 decreased due to the higher growth rate of installed capacity than the growth rate of power demand as well as the falling fuel prices, despite the factors that push up market prices such as a record low of the operating hours percentage of nuclear generators that resulted from the long outage period at Shin-Kori #1 & #2 and Shin-Wolsong #1 in the year. The lower the market heat rate is, the less fuel is spent to supply a unit amount of electricity, which means the high market efficiency.

Major fuel costs



Looking into the market heat-rate (MHR) of the past 10 years, the rate repeated ups and downs between 1.95 Gcal/MWh in 2011 and 2.08 Gcal/MWh in 2006 and 2007. In 2008 when the fuel cost jumped up a whopping 49.5%, the MHR was 2.04 Gcal/MWh, 0.04 Gcal/MWh down from 2007. The MHR in 2008 decreased because the market price increased 46.3%, a lower growth rate than that of fuel costs. The graph above shows that the market price is affected by fuel costs, availability of base load generators and the planned overhaul and as a result it moves differently from that of MHR, even when the fuel costs of the key price-setting LNG and oil are on the rise.

Trend of market prices, fuel costs[49] and market heat-rate



The above shows the development of yearly differences between the market price and fuel price and the market heat rate. The implication is that the narrower difference becomes and it raises efficiency of electric-power supply.

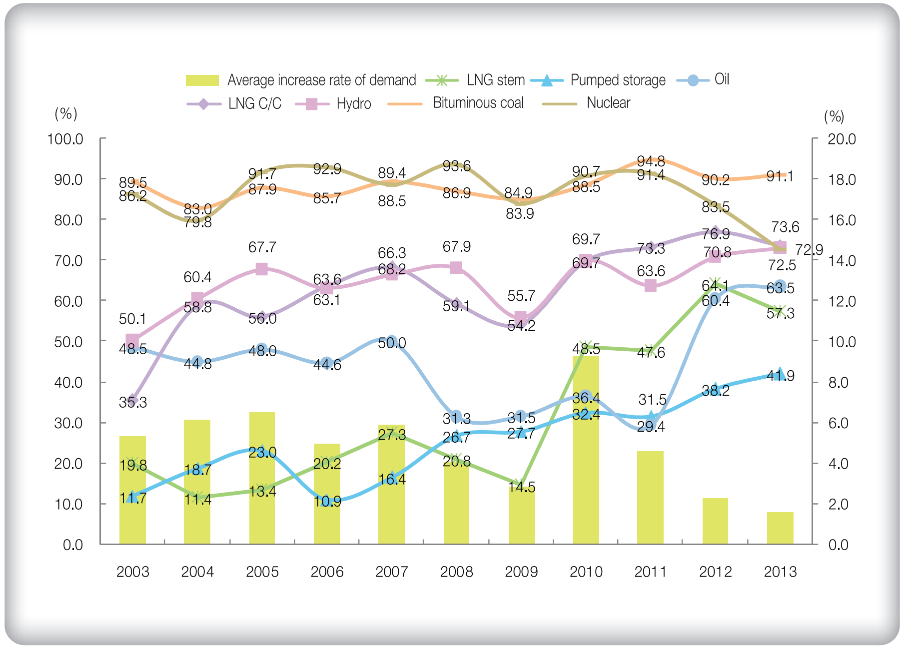
49) Difference between the increasing/decreasing rate of market prices and the increasing/decreasing rate of fuel costs = increasing/decreasing rate of market prices - increasing/decreasing rate of fuel costs

Utilization Efficiency of Generation

Operating Hours of Generators

The introduction of a market system in the power industry drove the GenCos to become more competitive and to innovate their management practices by enhancing efficiency and cutting down costs. Technically, the results of the electricity market operation can be reviewed in several aspects, but here in this report, only the generation aspect will be reviewed. The operating hours of generators can indicate efficiency of operating facilities in the current CBP system. The number of operating hours best reflects the efforts of GenCos to enhance the efficiency of power plant utilization, although the numbers are easily affected by: electric-power supply and demand status; constraints in the transmission network; power demand rise by region; the entry of new generating units; the self-constraints of generators; the failure of generation facilities; planned outages and others. Increasing the operating hours of base load generators such as nuclear and coal generators can considerably reduce the total production cost by expanding the supply capacity. The chart below shows the annual average generator-operating-hours percentage by generator type. The numbers are arrived at dividing the sum of the annual operating hours of each generator into the yearly sum of hours (8,784 hours in 2012) and then averaged by generator type. The annual average operating hours percentage by generator type went up in general when compared with that at the time of market opening. This is mainly due to the rise in power demand over the generation facility growth rate.

Annual average operating hours percentage by generator type



In 2013, the annual average operating hours percentage slightly decreased from 2012. Our analysis is that this decrease was mainly due to the average power demand growth rate at 1.6%, lower than the generation facility increase rate at 4.3%, as well as the low operating hours percentage of nuclear generators.

Generally, the annual average operating hours percentage of bituminous coal and nuclear generators are high. In 2013, however, the percentage of bituminous coal generators went up slightly whereas the percentage of nuclear generators decreased significantly from the previous year. The percentage of LNG CC generators, LNG steam generators and bituminous coal generators as well decreased year on year while the percentage of the generators by other fuel types increased during the same period. The percentage of LNG CC generators and LNG steam generators is coupled with the annual average growth rate of power demand. Particularly, the fluctuation of LNG steam generators[50] lies in its volatility to demand because of its small facility size.

In the annual average operating hours percentage of major generators[51] in 2013, the percentage of LNG CC generators is coupled with the average power demand growth rate due to the characteristics of peak load generators. The percentage has been on the increase since 2003. Because of the following factors: continuous rise in average power demand above the increase rate of base load facilities; the completion of low-cost CC generators; and increased generation by LNG generators due to a rise in oil prices.

However, the annual average operating hours percentage continued to fall in 2008 and 2009 from the previous years. The fall would probably have been affected by the decreased number of power generation opportunities for the increase in planned overhaul, the slow growth rate in power demand and the increase in base load generators[52]. On the contrary, the annual average operating hours percentage rose 15.5%p year on year in 2010. Our analysis is that the rise was due to the average power demand growth rate at 9.3% higher than the installed capacity growth rate of the year. The total capacity of base load generators decreased while the generation opportunities of the peak load generators increased with the shutdown of Incheon #3 & #4 in 2009 and construction of only one additional base load generator at Hadong #8 in June 2009 since 2008. In 2012, the average electric-power growth rate remained at 1.9%, a much slower growth from the previous year and large-capacity nuclear generators were installed. Therefore, the operating hours percentage of LNG CC generators seemed to be on the decrease. However, the year-on-year decrease in the annual average operating hours percentage of bituminous coal and nuclear generators traded off it. In the end, the operating hours percentage of LNG CC generators increased 3.6%p from 2011. In 2013, the average power demand increased while the growth rate remained slower from the previous year. The operating hours percentage of base load generators decreased 11%p year on year. In the meantime, the operating hours percentage of LNG generators decreased 3.3%p year on year to 73.6% with the remarkable growth rate of installed capacity of LNG CC generators at 12.4% from the previous year.

The operating hours percentage of hydro power generators significantly dropped by 12.2%p year on year in 2009 due to a cut in the year outflow to supplement the water loss of hydro generators caused by the drought in 2008. Since then, however, the percentage returned to the level of the previous years and thus the power generation output has been on the increase.

In 2013, the annual average operating hours percentage of oil generators increased 3.1%p from 2012 to 63.5%. One of the key contributors was a 1.2% decrease in the installed capacity of oil generators following the shutdown of Namjeju D/P in 2013. Another key contributor was the increased number of generation opportunities of oil generators as the average power demand increased while the trading volume of base load generators decreased from 2011. It is well demonstrated in the increase in the market price setting percentage and the trading volume of oil generators. The generation opportunities of oil generators increased drastically because they are highly responsive to demand as their generation facilities are smaller like LNG steam generators than other fuel types.

The nuclear base load generators have maintained a high level of operating hours percentage at above 90% except 2009 when the percentage decreased 9.7%p from 2008 because of the long outage period at Wolsong #1. In 2012, the percentage decreased 7.9%p to 83.5%, a lower percentage than those of the previous years. Also in 2013, the percentage remained low at 72.5%, an 11.0%p year-on-year decrease. In our analysis, the drastic fall of the operating hours percentage is due to the longer periods of failures and planned overhaul than those earlier including Wolsong #1 in outage since November 2012 for continued operation and Shin-Kori #1 & #2 and Shin-Wolsong #1[53] in outage for more than six months.

50) Seoul #4, 5 and Incheon #1, 2 are LNG steam generators (see Electric Power Statistics Information System (EPSIS) by KPX).

51) Major generators include hydropower, pumped-storage, LNG CC, bituminous coal, oil and nuclear generators.

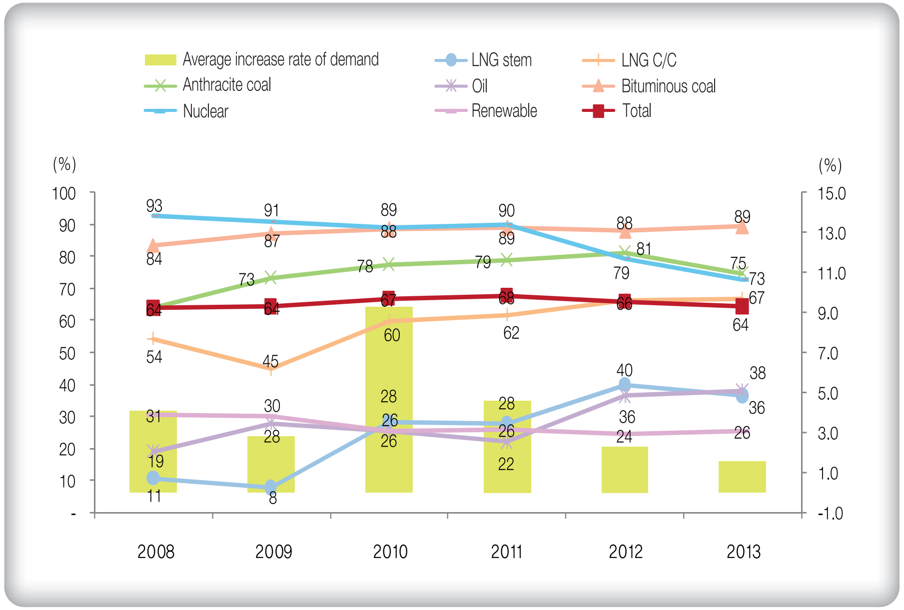
52) The new base load generators include Taeahn #7 & #8 and Dangjin #7 & #8 constructed in 2007, and Youngheung #3 & #4, Boryeong #7 & #8 and Hadong #7.

53) Wolsong #1 in outage from the termination of design life time since October 29, 2012; nuclear generators in outage for replacement of faulty parts (Shin-Kori #1 between April 8, 2013 and January 4, 2014; Shin-Kori #2 between May 29, 2013 and January 9, 2014; and Shin-Wolsong #1 between May 29, 2013 and January 4, 2014)

Capacity Factor by Generator Type and Ages

Since the current capacity payment system does not consider the generating efficiency or the depreciation of power generators, the GenCos may want to retain decrepit generators which will eventually lower industry efficiency. The efficiency of generator utilization can be measured by the capacity factor[54] of power generators classified by generator type and ages.

Capacity factor by generator type by year



The 2013 capacity factor by generator type followed the order of low variable costs: nuclear power 73%, bituminous coal steam power 89%, anthracite coal steam power 75%, LNG CC 67%, heavy oil steam power 38%, LNG steam power 36%, hydro power 28% and pumped storage 10%. The overall annual capacity factor in 2013 was 64%.

Capacity factor by generator type and year of completion (based on yearly generation in 2013)

(Unit: %)

Year of completion[55] / Generator type	1950s	1960s	1970s	1980s	1990s	2000s	2010s	Avg
Hydro	35	28	32	23	13	56	42	28
Pumped-storage	0	0	7	9	11	10	11	10
Bituminous coal steam power	0	0	71	87	91	89	0	89
Anthracite coal steam power	0	0	78	76	71	0	0	75
Heavy oil steam power	0	0	34	35	63	68	0	38
LNG steam power	0	38	36	0	0	0	0	36
LNG CC	0	0	0	0	62	74	61	67
LNG combined heat and power	0	0	0	40	41	45	46	50
Nuclear	0	0	49	78	75	94	35	73
Renewable	57	0	0	0	0	25	23	26
All	36	36	41	44	56	64	35	64

54) Generally, the capacity factor is calculated in reference to gross power generation. This report is, however, mostly based on the net power generation excluding loss -of-site power.

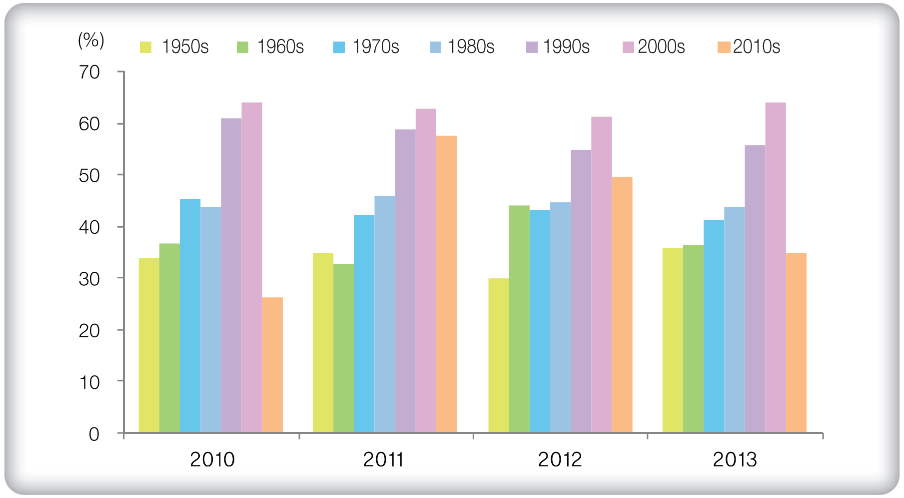
55) The capacity factor of generators completed before the 1950s (until 1949) was excluded in the above table, but included in the total capacity factor.

Compared with 2012, the total generation capacity factor decreased 1.6%p year on year along with the increased number of generation facilities over the increased average power demand in 2013. In the diagram above on the generation capacity factor and power demand by generator type, the portion of LNG CC, heavy oil steam power and bituminous coal generators slightly increased. The portion of new renewable energy generators went up along with the increase in installed capacity. Meanwhile, the portion of nuclear power, anthracite coal and LNG steam power generators decreased year on year. In 2013, there were more fuel types with the decreased capacity factor than the fuel types with the increased capacity factor, resulting in the overall decrease in capacity factor.

The capacity factor of generators by completion year shows: 36% in the 1950s, 36% in the 1960s, 41% in the 1970s, 44% in the 1980s, 56% in the 1990s, 64% in the 2000s and 35% in 2010s. As expected, aged facilities were less frequently used than recently-built generators. The generation capacity factor in the 2010s, however, remained low because of the falling availability of nuclear generators. In our analysis, that was because of the three nuclear power plants constructed in the 2010s (Shin-Kori #1 & #2 and Shin-Wolsong #1). Their capacity factor was low because of the outage period for replacement of faulty parts.

The diagram below shows the capacity factor of generators by completion year of recent four years. There was a fluctuation of the factor of generators completed in the 2010s. That was mainly because of the three nuclear generators constructed during the period as observed in the diagram above. The parallel in (synchronizing) at Shin-Kori #1 was carried out in the second half in 2010, and as a result the capacity factor was low in the year. In 2013, there was a severe fluctuation in the capacity factor of the generation facilities constructed in the 2010s because of Shin-Kori #2 and Shin-Wolsong #1 constructed in 2012 as well as Shin-Kori #1 in outage for a long time.

The trend of capacity factor of generators by completion year (as of 2013)



The current capacity payment program pays for all bidden capacity regardless of generators' depreciation or generating efficiency. This may induce the GenCos to retain older and less efficient generators that are paid by capacity. GenCos will try to retain generators aged more than usual service life, but whose life span can be extended by maintenance. GenCos may have to continue maintenance of the old generators in preparation of a shortage of electric-power supply and for sustainable supply in policy.

All those considered, the Electricity Market Surveillance Committee checks the level of availability by generator every year using the real-time test for availability supply capacity, and implement the procedure for autonomous corrective measures and cancellation of unfair profits when appropriate through the real-time dispatch orders. The activities aim to help the GenCos abide by the market rules. As part of the effort to improve the programs, the revision of the Electricity Market Rules is worth being considered in terms of the method of calculating the capacity payment in accordance with the availability.

Status of Demand Response Market

Demand Response MW

Demand response refers to a suite of policies and institutions to provide efficient and stable electric-power service at the lowest cost by helping consumers change their consumption pattern. Under the current contract-based utility rate schemes in Korea, consumers have a very weak incentive to participate in the demand response voluntarily. The current schemes do not reflect the values of electric power by location and time accurately.

Against this backdrop, the introduction of the demand response system[56] may be effective in stabilizing the electricity market and operation of its system. In other words, controlling the non-elastic power demand helps alleviate the supply shortage and stabilize market prices by transferring the peak load. The demand-response MW can play multi-purpose roles in curbing investment in the power system including generation, transmission and transformation networks; enhancing reliability in electric-power supply; and preventing GenCos from exercising market power.

Consumers can take part in the demand response market by reducing their consumption at critical times through monitoring their demand or securing a load that can be shut down by KPX and then make a bid on that load. The demand response can be used to confront the GenCos' attempts to exploit market power to raise prices and can even be used to reduce prices, making it harder for the GenCos to control the market. Thus, the demand response MW gained from managing the demand resources can indicate the system's reliability and capability to hold back market power exploitation.

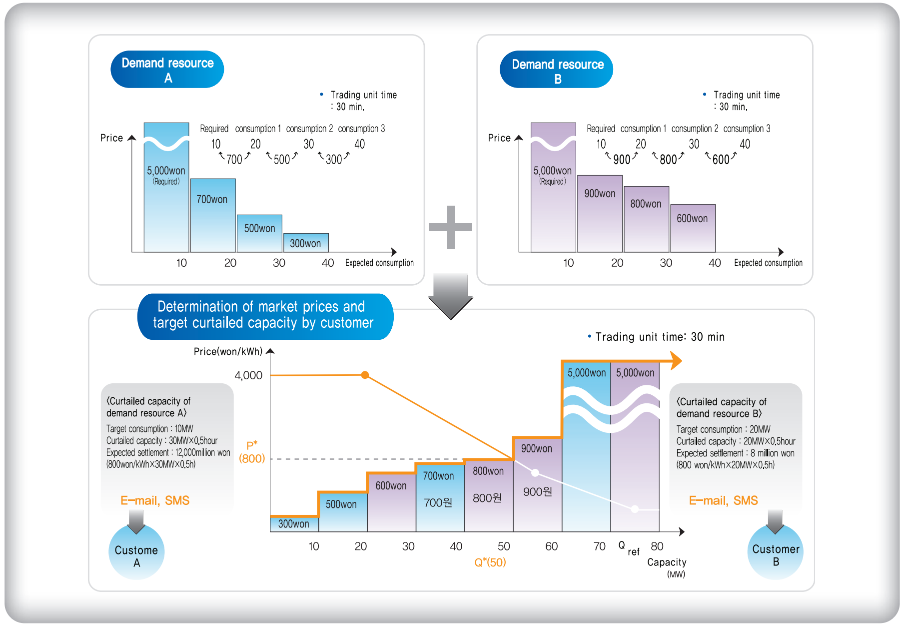
The new demand response market program adopted in 2008 operates in the following order: set up a Price Setting Schedule Energy (PSE) one day before the trading day. If the supply margin is expected to go lower than 6,000 MW, the demand response market will open a day or three hours before the trading day or trading time. The unit price on the curtailed energy and the target curtailed energy will be decided based on the shortage between the supply margin and the bid-price submitted by those consumers who can adjust their loads. Consumers will reduce actual power demand on the trading day by curtailing power and starting on-site generation. Payments will be made for the capacity to be curtailed and the energy actually curtailed. The demand response market that was pilot tested in 2008 succeeded in reducing the hourly average of 197 MW of power during the summer and 289 MW during the winter. The performance rate (average actual curtailed energy / target for curtailed energy) was above 100%.

Looking into the demand side management, KPX in cooperation with KEPCO has operated the day-ahead market and the hour-ahead market both of which are a form of spot markets since 2009. KEPCO introduced the two-month-ahead program and the week-ahead program as a form of a forward contract. The programs are similar to the outage schedule adjustments during summer vacation or the energy-saving campaign.

Some parts of the operating rule of the demand response market were revised in 2010 and the major revisions include: (1) the reserve required to establish the demand response market was revised to less than 5,000 MW so that it does not fall below an emergency level of 4,000 MW, and (2) the capacity payment settlement standard was integrated into the bid data of the hour-ahead market from the bid data of the day-ahead market and the hour-ahead market. In 2011, the capacity payment settlement standard was abolished. In determining the load curtailed energy volume, the amount of availability became the standard and the larger amount was reflected on priority.

56) Demand response basically refers to a strategy to boost the role of demand in pricing and market clearing in the competitive electricity market. Real-time pricing linked to the wholesale market, one of the demand response types, reduces demand in hours of high prices and raises it in hours of low prices when applied to clients. At large, the pricing steadily maintains a certain level of demand in the system, and thus cuts the whole facility cost and enhances reliability of electric-power supply.

Determination of bidding, market prices and target for curtailed energy



In 2012 as well, some parts of the operating rule of the demand resource market were revised and the major revisions include: (1) the reserve required to establish the demand response market was revised to be estimated less than 4,500 MW, (2) a new provision was added to the rule in case of the emergency electric-power supply to include details on notification time of market opening, description, submission of bid documents at system operator's request of load curtailment to the market participants because of the shortage of capacity reserve, and (3) a provision was revised to enhance reliability by improving the method to assess the actually curtailed volume, and (4) the smart demand response market was established for operation so that the smart grid service providers can utilize smart grid technology to explore new small and medium sized demand resources necessary for load curtailment in case of power shortage emergency.

In 2013, the operating rule of the smart demand response market was revised and the major revisions include: (1) autonomy in demand response management by allowing aggregators to register or withdraw demand response resources, breaking away from the KPX-led practice of operating and evaluating the resources, and (2) on the other hand, revision adjusting the standard for financial penalty against violation of load curtailment orders (from below 80% to below 90%) in order to enhance reliability of the demand response market. In the same year, 30-minute-ahead market in case of emergency was newly introduced in addition to the existing day-ahead market and hour-ahead market in order to closely link with the system operation. With the greater goal of curtailing load, the target curtailment volume increased 10.5% year on year to 840 MW and finally the actually curtailed volume reached 988 MW.

The diagram below describes the rising demand curtailment and the falling market prices in recent five years (2009 - 2013). The actually curtailed volume increased because of more participation of the existing customers and an entry of new customers. As the market system settled down and the acceptance rising among the market participants grew and their competition escalated, market prices showed large drop. The demand response market will serve as a powerful means for stable electric-power supply in response to uncertainty in increasing facilities for supply and surge in demand. From the perspective of market monitoring, the increasing demand curtailment volume and the falling, stable market prices are considered excellent resources to relieve the market dominance in operating the market. The revision of the Electricity Business Act is in progress under the plan for integrating the demand response market into the electricity market with the goals of obtaining reliability of the demand response program and boosting the demand response market. If the integration materializes, uncertainty in demand will be cleared and market dominance will be mitigated while energy economy will grow in the demand response market.

Demand curtailment volume[57] and market prices by year

57) Market prices refer to the average curtailment cost per kWh in the demand response market.

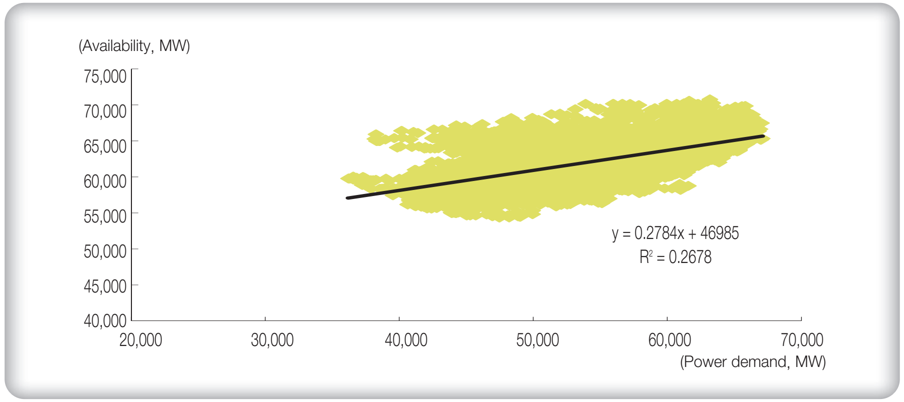
Market Participants' Behaviors

Capacity Bid

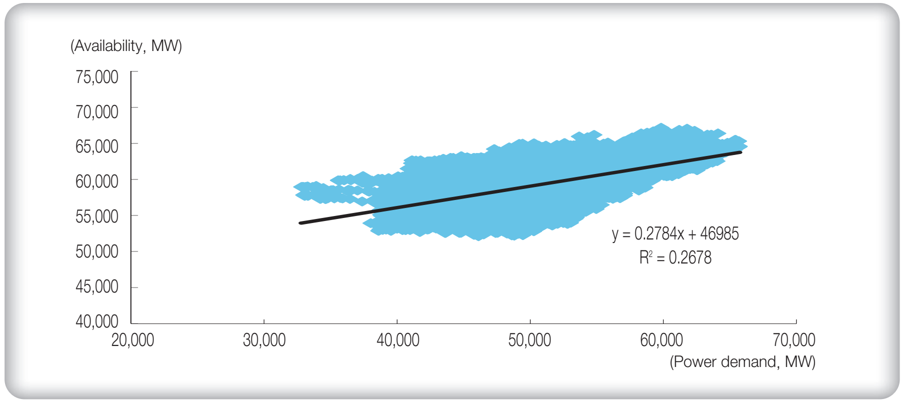
Available Capacity by Power Demand

Under the current CBP, power generators' data such as unit technical characteristics, heat-rate, variable-cost and availability determine which power generator will join the production. Therefore, if the GenCos intend to cheat, it is more difficult to spot the forged data and take corrective action than to manage bidding where the price is the only variable. Also, if electricity companies strategically bid their capacity, adjust their outage periods and forge forced outages, it may cause inefficiency in the distribution of resources. The charts below show the correlation between the annual power demand and supply availability in recent four years from 2010 to 2013.

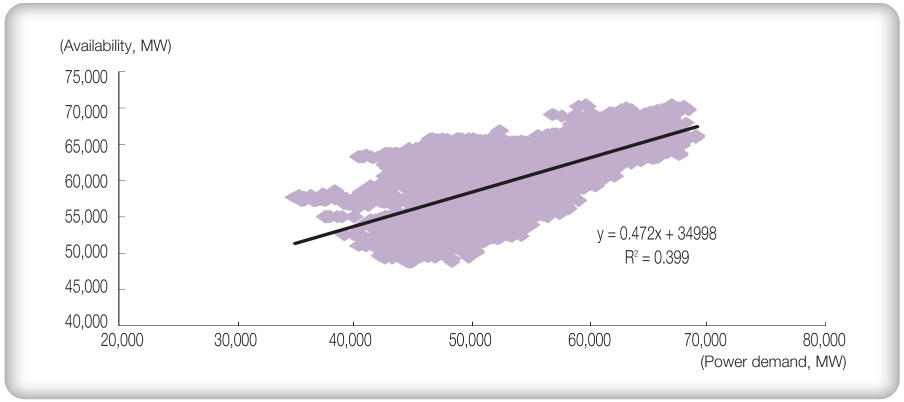
Correlation between power demand and availability (2010)



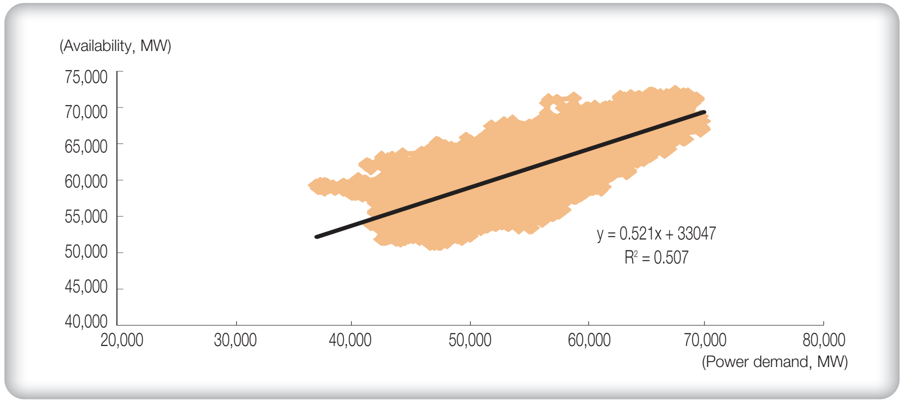
Correlation between power demand and availability (2011)



Correlation between power demand and availability (2012)

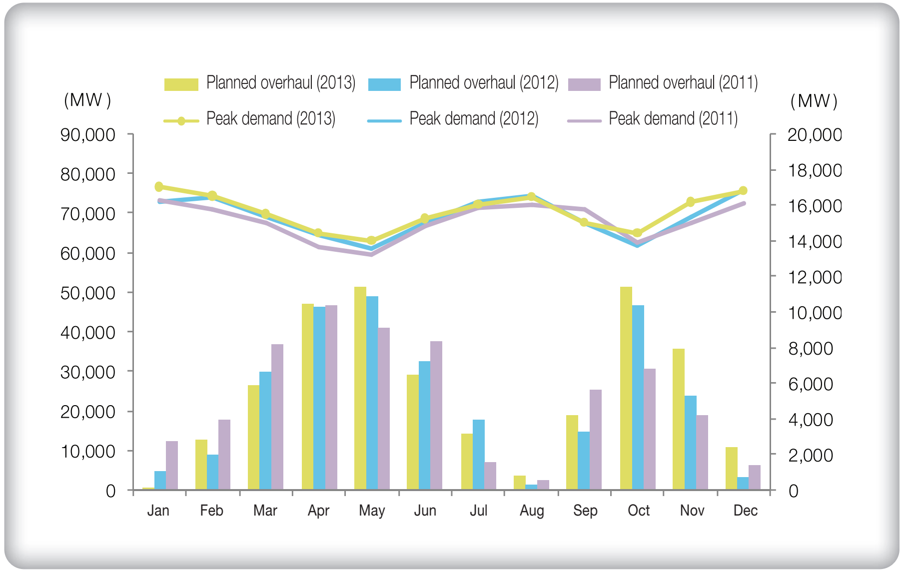


Correlation between power demand and availability (2013)



The charts above show that the correlation between power demand and availability is different each year. The correlation has increased for years: 0.550 in 2010, 0.518 in 2011 and 0.632 in 2012, and 0.712 in 2013. Looking into the chart in 2013, the slope of the line was steeper than ever and thus the elasticity of availability was high. This implies that the allocation of power generation resources became efficient in 2013 than the previous years by adjusting the schedules for planned overhaul or maintenance, key factors that affect the availability of generators. See the development of the monthly peak demand and the planned overhaul in recent three years for further details.

Monthly peak demand and daily average planned overhaul development in recent three years (2011 - 2013)



In terms of the planned overhaul performances between 2011 and 2013, the daily average planned overhaul performance in the peak demand of summer (July and August) and winter (January, February and December) was 1,866 MW, an increase from 1,606 MW in 2012 but a decrease from 2,038 MW in 2011. In the other months of 2013, the number stood at 8,253 MW, an increase from 7,717 MW in 2012 and 7,526 MW in 2011. From 2011 to 2013, the power demand and the planned overhaul showed a similar trend including the annual peak demand occurred in winter and the planned overhaul carried out mainly in April and May each year. In 2013, however, the planned overhaul was very limited in summer and winter in high power demand and instead it was scheduled during the other days of the year. Our analysis is that it mainly raised the correlation. Fewer planned overhauls were scheduled in summer and winter 2013 than those in 2012, but more than those of the previous years. It probably means that KPX operated the generators in line with the electric-power supply and demand in scheduling the planned overhaul. It equally means that GenCos did not push up the market prices to a degree of disrupting the market nor lay out a strategy to receive capacity payment overly.

The high correlation in 2013 also results from the improved accuracy in demand forecast. As stated before, availability is affected by the planned overhaul and maintenance periods. However, it is more closely linked to demand forecast that sets a basis for scheduling of generators. We prepare a plan of operating generators depending on the demand forecast and thereby adjust the schedule for the planned overhaul or maintenance. Again, demand forecast affects availability of generators much. A number of factors including weather and demand pattern changes increasingly raised uncertainty in demand forecast and efforts were made to minimize the uncertainty and improve the demand forecast error ratio. First of all, a demand forecast program was improved by reflecting the more approximate value of weather and social conditions and running it 24 hours all through the year. The demand forecast technique became more precise with the forecast on a 15-minute-cycle basis from the previous one-hour-cycle basis. A pool of experts in demand forecast developed a technique for analysis on demand forecast error ratio and its application. In the long term, many efforts are being made to develop techniques to respond to uncertainty in demand forecast and demand forecast modeling. The error ratio of demand forecast was lowered in 2012 and 2013 and it is considered to have raised the correlation of the availability to power demand. At the time of the national rolling blackout in September 15, 2011, demand forecast error was pointed out as one of the main causes of the problem.

Derated Power of Coal-fired Generators

Close monitoring on each outaged or derated generator is needed to prevent electricity companies from bidding less than their availability under the pretense of a forced outage. If the power demand goes up near the total available installed capacity and a forced outage occurs in these circumstances where it could actually force up the prices and if the frequency of forced outages is more than usual, then special attention is required. Also, when the availability of all coal-fired generators can meet the power demand, but there are forced outages more often than the normal level when gas generators need to operate; this also requires scrutiny. In other words, these are the times when price-manipulation works best. However, not only the peak-hours short of the reserve margin, but the sensitive range on the supply curve where price-setting generators change from coal to LNG need close monitoring.

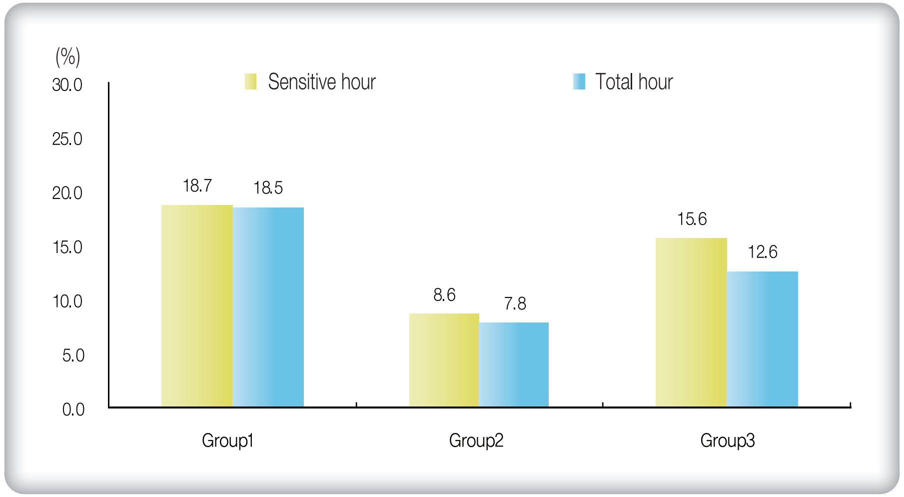
The chart below as of 2013 compares the derating ratio[58] of anthracite generators (Group1), bituminous-coal generators (Group2) and the top-five high-generation priced bituminous-coal generators (Group3)[59] to the annual average (8,760 hours) derates of each group when the power demand reached the sensitive range[60] on the supply curve.

58) Percentage of derated electricity: (installed capacity - availability)/installed capacity

59) The top five coal-fired generators whose generation prices were most frequently included in the top 20% highest hourly-generation prices.

60) It means a load range where marginal generators are converted from coal-fired generators to LNG CC. This track (39,000 MW - 42,000 MW) was set in reference to the Market Review released in 2013.

Derated power during the sensitive hours compared to the annual average derates (2013)



The diagram also shows that the derates in 2013 (18.7%, 8.6% each) of anthracite coal generators (Group 1) and bituminous coal generators (Group 2) during sensitive hours were slightly higher than the annual average derates of the two groups (18.5% and 7.8%). The number of anthracite coal generators was small, so they were affected by the planned overhaul schedule of other generators and the anthracite coal generators showed no sign of change. Indeed, most of the derates of anthracite coal generators appeared in the intensive planned overhaul period in April, May in the first half and October in 2013. The relatively high derates compared with power demand in November and December were mostly due to the planned overhaul at Donghae #1 & #2 and Youngdong #1 during the period. For bituminous coal generators, there was no special sign in their curve during the sensitive hours. The planned overhaul also affected the derates; more than 50% of the derates appeared during the planned overhaul period in April, May, and October. Still, it is remarkable that 15% of the derates of bituminous coal generators appeared in November when the winter peak demand started. The high number resulted from the increased capacity following the planned overhaul in November in anticipation of the coming winter at Boryeong thermal power plant #8 and Dangjin thermal power plant #6. There were no other particular findings.

The derates for the top five high generation priced bituminous coal generators (Group 3) whose generation prices were most frequently included in the leading group were 15.6% during the sensitive hours, higher than the annual average. The derates of the generators were high between April and June and between October and November and there were no other particular findings. This shows no evidence that reduction in the bid volume had relatively high influence on price rise leading to intended bidding for derates was not found. It is probably because most coal-unit owners are KEPCO subsidiaries who have little incentive to raise market prices for their other type generators to maximize operating profits.

With the steadily rising power demand, the price-setting percentage of LNG and oil generators accounted for 99% in 2013. Accordingly, GenCos are less likely to push up the market prices in the sensitive range of the capacity curve using derates-based bidding of anthracite generators and bituminous coal generators. As stated earlier, now the capacity payment of base load generators has drastically decreased from that of the market opening. In the meantime, the KEPCO subsidiaries that operate the base load generators receive their payment based on the settlement adjustment factors. The subsidiaries are hardly likely to make use of the derates-based bidding of base load generators to maximize their profits[61). If the increase in power demand begins to slow and the private GenCos complete their design and finally own their base load coal-fired generators, the market landscape will probably change. However, derates-based bidding is just part of the discussion on whether or not the market power is exercised. Multiple approaches should be taken to review it including the periods of the market price hike and the resulting profits from derates.

61) The capacity prices of base load generators used to be high. Against this backdrop, there were low strategic incentives to increase the SEP of other own generators by accepting the decrease in capacity payment and raising market prices through derates-based bidding.

Conclusion

Market operation: The market price in 2013 decreased 5.4% year on year, a stark contrast to the 27.0% increase in 2012. Similarly, there were merely 56 price-setting times in the prices above 200 won/kWh, accounting for less than 1% in the price- setting percentage. Earlier in 2012, on the other hand, there were 1,108 price-setting times. The capacity payment rarely changed from the previous year because of the freeze in the reference capacity price. Yet, the share of capacity payment that had been on the decline until 2012 out of the total settlement payment slightly went up because of the increase in bid capacity coupled with the increase in installed capacity, the introduction of the Soft Price Cap and the decreased percentage of energy payment caused by the decline in fuel costs. As the trading scheme is established in the electricity market, the rapid increase of supply by private GenCos at 10.6% in 2013 from 0.1% at the time of the market opening contributed to the growing market vitality.

Power system operation: While the level of the installed reserve margin stayed stable during the peak load season of the years between 2001 and 2005, it has dropped down to a single digit since 2006, raising the concerns over stable power supply. In 2008, the reserve margin returned to 12% temporarily as the installed capacity increased with the construction of Youngheung #3 & #4 and Boryeong #7 & #8 while the peak demand increased merely 0.4% because of the economic downturn. Since then, the power demand increased more than the growth rate for generating capacity and therefore the installed reserve margin was on the decrease to a record low at 4.1% in 2011. In 2012, the growth rate for generating capacity was 7.5% and the installed reserve margin increased 3.6%p to 7.7% by turning around from the continued decrease since 2008. The peak demand in 2013 hit 76,522 MW, a 0.7% year-on-year increase, on Thursday, January 3. The installed capacity reached 82,296 MW and the reserve margin stood at 7.5%. The reserve margin has been unstable at a single digit number since 2009 until recently, but it is expected to increase to 16% - 30% beyond 2014. Over the long term, the power supply is predicted to become more stable.

As for the expansion of power transmission and transformation facilities in 2013 that directly affect the supply reliability and transmission constraints, the growth rate of transmission facilities stood at 2.0%, higher than the annual average of recent five years at 1.3% (2008-2012). The growth rate of transmission facilities slightly decreased to 3.1% compared with the annual average of recent five years (2008-2012) at 3.5%. Transmission and transformation facilities and power plants in the Seoul metropolitan areas need to be expanded more to address the transmission constraints as peak demand and transmission interchange flow seem to be on the rise in the areas.

Market structure: The trading volume shares by GenCos operating the base load nuclear or coal generators at a certain level all through the year decreased as those of the LNG or oil generators increased along with the increased power demand. Accordingly, the trading volume shares of the top three generators continued to fall to 55% in 2013. By the standard of the HHI that indicates the level of market concentration by trading volume, their market shares significantly decreased from those of the market opening.

Market performance: In 2013, the fuel price decreased 2.5% whereas the market price decreased 5.4% year on year. The market heat rate thus decreased to 2.01 Gcal/MWh in 2013 from 2.07 Gcal/MWh in 2012, raising the efficiency of electric-power supply. In terms of generation utilization efficiency, the entire annual average operating hours percentage slightly decreased from 2012. The decrease seems to be due to the additional facilities over the average power demand growth rate. In particular, nuclear generators showed the lower operating hours percentage than in the previous years because of the long outage period at Shin-Kori #1 & #2 and Shin-Wolsong #1 for replacement of faulty parts. The demand response market introduced in 2008 saw the existing market participants' curtailment increasing and the increased number of new participants. With the competition escalating, the annual sum of demand curtailment increased while the market price decreased. The revision of the Electricity Business Act is in progress for the incoming integration of the demand response market into the wholesale electricity market. The integration aims to enhance reliability in demand response resources and boost the demand response market. If the revision bill is passed, the further development of the demand response market is expected to bring about power supply stability and economic efficiency.

Market participants' behavior: The elasticity of availability to power demand was high in 2013. It means availability was elastic to power demand in its movements. Availability is affected by planned overhaul, bidding and demand forecast. During the peak power demand over summer and winter, there were shorter planned overhaul days; the planned overhaul was scheduled on the other days of the year in response to power demand properly. Moreover, GenCos did not conduct any strategic behavior to raise market prices by disrupting the market or to receive overly-charged capacity payment. Many efforts were made to reduce uncertainty in demand forecast as much as possible in the wake of the national rolling blackout in September 15, 2011. Indeed, the demand forecast error ratio was lowered in 2012 and 2013 in a row. A series of these actions seem to have affected the increased correlation of availability to power demand. Last but not least, in terms of the derates of coal-fired generators, the LNG generators and oil generators accounted for 99% of the total price-setting generators with the rising power demand. Against this backdrop, it was considered that the GenCos were not likely to raise the market prices using the derates-based bidding of generators of anthracite and bituminous coal in the sensitive hours of the supply curve.

With all of the above considered, it looks hard for some GenCos to exercise market power or conduct strategic behavior to make unfair profits in the electricity market today given the unstable supply and demand as well as the market structure. However, close monitoring on private GenCos should be continued as a sweeping change will come because of their plan to construct coal-fired power plants, the falling power demand growth rate, the rising reserve margin, and the growing installed capacity share of the generators based on new renewable energy.

Appendix

Market Participants

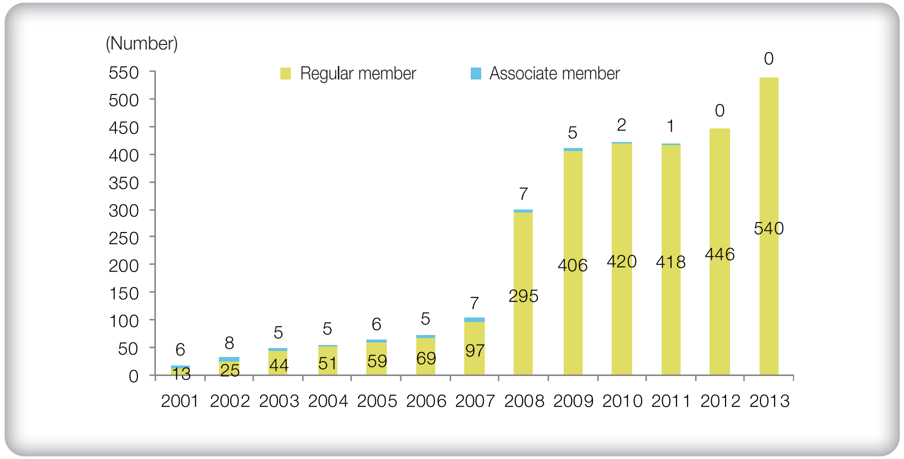
At the beginning of the market, there were about 10 market participants including KEPCO and its six subsidiaries. Since then, the number of members has steadily increased to 540 as of 2013.

That is, from the beginning of the market to early 2003, community energy businesses and small hydro-electricity companies joined the electricity market as their contracts with KEPCO expired. As KEPCO ended its PPAs with community energy businesses at the end of 2002, 15 companies including Hyundai Heavy Industry Co. Ltd. joined the market as of Jan. 1. 2003. Since 2003, small electricity companies of wind, LFG and photovoltaic generation have entered the market with the support of government policy for renewable energy development. The number of market participants soared to 446 as of 2012. The number increased again to 540 in 2013 as another 90 new renewable energy GenCos joined the electricity market.

Market participants (as of the end of 2013)

Classification	Name
Transmission, transformation and retail supplier	KEPCO
KEPCO generating subsidiaries	6 companies including KHNP
GenCos	9 companies including POSCO ENERGY
Renewable energy businesses (GenCos)	473 companies including MPC Yulchon Generation Co., Ltd.
Community energy supply businesses	10 companies including Yeochun NCC Co., Ltd.
Direct purchase customers	-
Community energy businesses	22 companies including KG ETS
Self-generation installers	19 companies including Byeollae Energy Co., Ltd.
Associate members	-
Total	540

Trend of market participants by year



Abbreviations

AGC: Automatic Generation Control
BLMP: Base Load Marginal Price
CBP: Cost Based Pool
CC: Combined Cycle Power Plant
CON: Constrained-On energy payment
COFF: Constrained-Off energy payment
CP: Capacity Payment
EMSC: Electricity Market Surveillance Committee
G/F: Governor Free
GSCON: Generator-Self Constrained-On energy payment
IPP: Independent Power Producer
ISO: Independent System Operator
KDI: Korea Development Institute
KEEI: Korea Energy Economics Institute
KERI: Korea Electrotechnology Research Institute
KEPCO: Korea Electric Power Corporation
KEWESPO: Korea East-West Power Co., Ltd.
KOWEPO: Korea Western Power Co., Ltd.
KHNP: Korea Hydro & Nuclear Power Co., Ltd.
KOMIPO: Korea Midland Power Co., Ltd.
KOREC: Korean Electricity Regulatory Commission
KOSEP: Korea South-East Power Co., Ltd.
KOSPO: Korea Southern Power Co., Ltd.
KPX: Korea Power Exchange
LFG: Landfill Gas
MHR: Market Heat Rate
MOCIE: Ministry of Commerce, Industry and Energy (current Ministry of Knowledge Economy)
PPA: Power Purchase Agreement
PSE: Price Setting Scheduled Energy
RMP: Regulated Market Price
RPS: Renewable Portfolio Standard
RSC: Resource Scheduling & Commitment
SCON: System Constrained-On energy payment
SMP: System Marginal Price or market price

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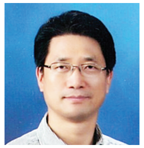

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Electricity Market Trends & Analysis

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