The 5th Basic Plan for Long-term Electricity Supply and Demand

(2010 ~ 2024)

December 2010

Ministry of Knowledge Economy

Korea Power Exchange

This translation was prepared by KPX in December 2010. In the event of any discrepancies in interpretation, the Korean text shall prevail.

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1. Background and Objectives

A. Legal Background

□ The 5th Basic Plan for Long-term Electricity Supply and Demand (hereinafter "BPE") is prepared pursuant to Article 25 of the Electricity Business Act (EBA) and Article 15 of the Electricity Business Decree. The EBA requires the Ministry of Knowledge Economy (hereinafter "MKE") to prepare and announce the BPE on a biennial basis.

○ The BPE stipulates electricity policy directions on supply and demand, long-term outlook, construction plans, DSM, etc.

B. Objectives

□ The plan shall provide electricity policy directions, information on electricity supply and demand outlook, and the electricity capacity plan to secure electricity supply.

C. Procedure

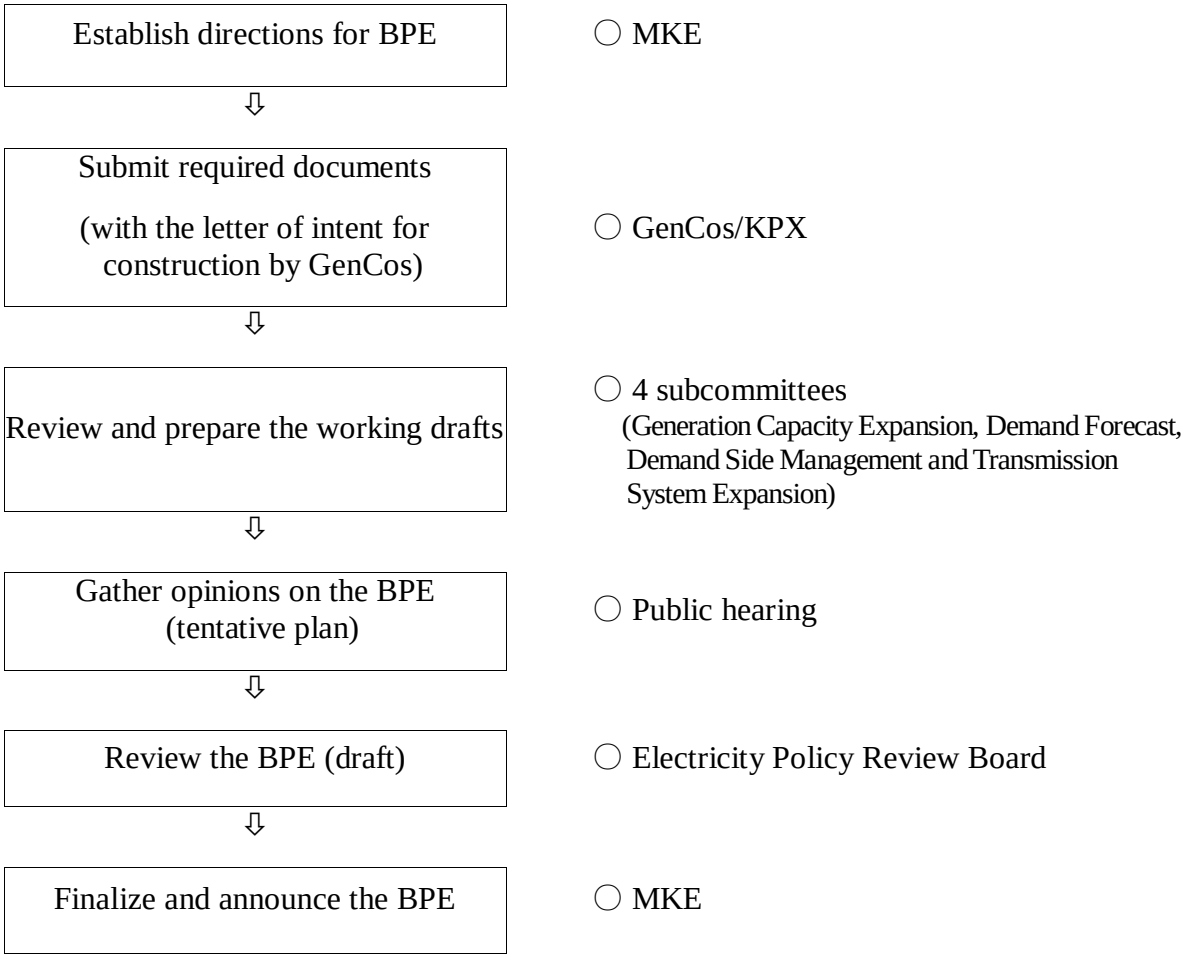
□ Four subcommittees consisting of experts from universities, research institutes, electricity companies, and other organizations shall submit study reports individually.

* 4 subcommittees: Generation Capacity Expansion, Demand Forecast, Demand Side Management (DSM) and Transmission System Expansion.

□ The BPE shall be made based on the construction intentions of GenCos and the demand forecast provided by Korea Power Exchange (hereinafter "KPX").

□ The government shall gather and review ideas and opinions on every aspect from various stakeholders on the plan through a public hearing process, and shall finalize the BPE by incorporating comments from the Electricity Policy Review Board on the plan.

Figure 1.1 Procedures for BPE Establishment



2. Direction of the BPE

A. Planning Period: From 2010 to 2024 (15 years)

B. Strengthening the Planning Functions

□ Maintaining consistency with other energy plans such as the National Energy Basic Plan (hereinafter "NEBP").

□ Expanding base load generators gradually to establish an economic electricity supply system.

□ Creating countermeasures against demand forecast uncertainty and construction delays in order to secure a stable electricity balance.

□ Strengthening load control in 2011 ~ 2014 to address short-term supply difficulties caused by a low reserve margin.

C. Establishing an Eco-friendly Generation Mix

□ Establishing an eco-friendly generation mix in order to reduce greenhouse gas emissions.

○ Construction intents for nuclear generators are preferentially reflected in the 5th BPE.

○ Estimating and reflecting a more realistic capacity expansion taking into consideration RPS targets, resource potential, construction intents by Gencos, and relative weighting on resources, etc.

D. Minimizing Uncertainties of the Supply and Demand Outlook

□ Taking measures against any uncertainties in the demand forecast by establishing the BPE against any demand forecast error.

□ Securing planning effectiveness by inducing evaluation improvements and studying construction delays of reflected capacities in past BPEs, and strengthening the implementation of the BPE so that a more reliable system operation is attained.

E. Strengthening Expertise and Transparency in the BPE Establishment Process

□ Organizing an Electricity Supply-Demand committee and 4 subcommittees composed of experts in each field.

○ Electricity Supply-Demand committee (18 persons)

○ 4 working subcommittees: Generation Capacity Expansion (18 persons), Demand Forecast (14 persons), Demand Side Management (13 persons), Transmission System Expansion (16 persons)

□ Organizing additional professional working groups to enhance available expertise and to review the current agenda and provide technical advice on the BPE.

3. Milestones

□ Basic directions for the 5th BPE were set and working subcommittees established. (April 2010~)

○ Directions for the BPE were set towards securing electricity supply stability and expanding eco-friendly generators and low cost base-load generators.

○ Composition of subcommittees.

* Working subcommittee meetings were held: Electricity Supply-Demand (twice), Generation Capacity (6 times), Demand Forecast (3 times), Demand Side Management (4 times), Transmission System Expansion (3 times).

○ Composition of working group.

* Three areas related to the Generation Capacity Subcommittee (Evaluation standard of construction intents, RPS, Supply Reliability)

□ Conducting surveys on 「Generation Capacity Expansion and Retirement Intention」 with GenCos were conducted. (March ~ April 2010)

□ Forecasting electricity demand taking into consideration the economic growth rate, changes in industrial structures, latest electricity demand, and other circumstantial changes. (April ~ September 2010)

□ Establishing a Reference Generating Capacity plan and Generating Capacity Expansion Plan based on electricity demand. (May ~ October 2010)

□ Assessment of GenCos' letters of intent for construction. (September ~ October 2010)

□ Setting of mid- and long-term electricity supply and demand plans based on the generation capacity plan. (October 2010)

□ Holding a public hearing on the 5th BPE draft on December 7, 2010.

□ Holding an Electricity Policy Review Board meeting to discuss the 5th BPE draft. (December 16, 2010)

□ Finalizing and announcing the 5th BPE draft. (December 29, 2010)

II. Long-term Electricity Supply and Demand Outlook

1. Recent Status of Electricity Supply and Demand

2. Mid- and Long-term Demand Forecasts

3. Future Supply and Demand Outlook

1. Recent Status of Electricity Supply and Demand

A. Electricity Supply and Demand

□ Electricity consumption has continuously increased due to its convenience and stable cost.

○ Electricity consumption per capita has increased from 859kWh/year in 1980 to 8,092kWh/year in 2009, an increase of approximately 9 times.

□ Installed capacity has increased from 9,391MW in 1980 to 73,470MW in 2009, an increase of approximately 8 times, due to the increase in electricity demand.

○ By the late 2000's, electricity supply concerns have become quite serious due to the increased growth in demand.

* This is the result of a complex set of factors including demand forecast errors, excessive demand-side management targets, switching demands due to the relative price differences in fuels, and so on.

* The energy environment has changed rapidly due to skyrocketing world oil prices since 2003.

Table 2.1 Recent status of electricity supply and demand

Year	1980	1990	2000	2005	2006	2007	2008	2009
Peak Load (MW)	5,457	17,252	41,007	54,631	58,994	62,285	62,794	66,797
Generating Capacity (MW)	9,391	21,021	48,451	62,258	65,514	68,268	72,491	73,470
Reserve (%)	72.1	21.8	16.8	13	9.8	7.9	12	9.8
Consumption per capita (kWh/year)	859	2,206	5,067	6,883	7,191	7,607	7,922	8,092
Nominal Electricity Price (Korean Won/kWh)	50.9	52.9	74.7	74.5	76.4	77.9	78.8	83.6

B. Supply and Demand Environment

□ Gradually increasing uncertainty over electricity supply and demand conditions

○ Uncertainty factors

- Demand side: demand forecasting methodologies, demand forecast errors such as altered preconditions, and excessive demand management targets (or lack of demand-side management, etc.)

  * Uncertainty over demand growth has increased sharply due to the demand switch (from other energy sources to electricity) resulting from relative fuel cost differences in the demand side.

- Supply side: construction delays

  * Uncertainty over construction completion being on time due to increasing numbers of large-scale new power plant construction projects, difficulties in securing available sites for plant construction, and increasing civil complaints.

□ Countermeasures against greenhouse gas reduction in the power sector

○ It is expected that reduction goals will be set by sector in 2011 as a follow-up to the national mid-term greenhouse gas reduction target already set (30% reduction compared to BAU in 2020).

○ A reduction in greenhouse gas emissions is expected to start in earnest by setting a reduction goal in the power sector and establishing emission allocations for individual facilities.

  * Improving energy efficiency, expanding renewable and nuclear generation, etc.

□ Difficulty in securing mid- and long-term capacity expansion and supply reliability

○ Increasing civil complaints over the construction of power facilities

- Making existing plant sites larger and forcing limits on the construction of new transmission lines

○ It is necessary to make a change in planning direction from cost minimization planning in the past to strengthening supply stability and establishing sustainable power systems for low carbon green growth.

○ Social acceptance of nuclear and renewable energy is expected to increase, while that of fossil fuel energy (coal and LNG) to decrease.

2. Demand Forecast

A. Recent Status of Electricity Demand

1) Electricity Consumption

□ Electricity consumption growth rates (annual average) have gradually decreased

* 16.7% in 1970s → 10.8% in 1980s → 9.5% in 1990s → 5.7% in 2000s

○ Residential sector: 8.6% in 1990s → 6.2% in 2000s

○ Commercial sector: 13.9% in 1990s → 7.4% in 2000s

○ Industrial sector: 8.2% in 1990s → 4.6% in 2000s

(The electricity consumption growth rate for the commercial sector is the highest of all)

Table 2.2 Annual average electricity consumption increase (unit: %)

Period	Residential	Commercial	Industrial	Total
'70~'79	22.6	12.6	16.7	16.7
'80~'89	12.4	13.9	9.6	10.8
'90~'99	8.6	13.9	8.2	9.5
'00~'09	6.2	7.4	4.6	5.7

□ The electricity consumption growth rate barely reached 4.5% in 2008 and 2.4% in 2009 due to economic recession, but is expected to increase to 7.8% in 2010.

○ Due to economic recovery and an increase in the numbers of electric heaters in use

○ Relatively low cost of electricity resulting in a demand switch from other energy to electricity

□ Actual consumption over the past 3 years ('07~'09) is recorded as being 3~5% higher than the original forecast (the average of demand forecast data from the 1st BPE to the 4th BPE).

Table 2.3 Electricity consumption forecast error

Year	Original forecast (GWh)	Actual (GWh)	Forecast Error(%)
2007	350,970	368,605	5.0
2008	369,297	385,070	4.3
2009	381,916	394,475	3.3

2) Peak Demand

□ The peak demand growth rate (annual average) has gradually slowed down.

* 14.7% in 1970s → 11.9% in 1980s → 8.9% in 1990s → 5.6% in 2000s

○ However, the amount of peak demand growth (annual average) has increased.

* 422MW in 1970s → 1,067MW in 1980s → 2,227MW in 1990s → 2,866MW in 2000s

□ The peak demand growth rate reached only 0.8% (an increase of 509MW) in 2008 due to economic recession and abnormal low temperatures during the summer, but at the end of 2009, annual peak demand was instead recorded in the winter due to the economic recovery and an abnormal cold snap (a 6.4% increase compared to the previous year). In 2010, summer peak demand increased by 4.6% compared to the previous year's (winter) peak

□ (Summer) Peak demand is highly affected by weather factors such as the number of days of high temperatures and the number of tropical nights.

Table 2.4 Days of high temperatures and tropical nights

Year	2005	2006	2007	2008	2009	2010
Days of high temperatures	5	18	7	3	7	4
Days of tropical nights	0	4	1	0	0	1

※ Days of high temperatures: the number of consecutive days whose maximum temperature is above 30℃.

※ Days of tropical nights: the number of consecutive days whose minimum temperature is above 25℃.

□ As the share of weather sensitive loads has recently increased among summer and winter peak demands, temperature induced volatility has gradually increased.

Table 2.5 Share of electricity demand sensitive to daily air temperature (unit: %)

Year	2005	2006	2007	2008	2009	2010
Summer Peak	21.2	21.9	23.0	20.9	20.2	22.0
Winter Peak	18.6	19.8	22.0	22.6	24.1	-

B. Reference Demand Forecast

1) Assumption for Demand Forecast

□ Economic growth forecast (data from the Korea Development Institute (KDI))

○ The GDP forecast of the 5th BPE is similar to that of the 4th BPE.

- An annual average rate of 3.9% is forecasted for the period 2010 ~ 2024 (a similar level to data from the 5th BPE)

Table 2.6 GDP growth forecast (unit: %)

Year	2010	'11~'15	'16~'20	'21~'24	'10~'24
5th BPE	5.9	4.2	3.9	3.2	3.9
4th BPE	5.0	4.4	3.8	3.1	3.9
Difference	0.9p↑	0.2p↓	0.1p↑	0.1p↑	-

2) Forecasting Methodologies

□ Electricity consumption forecast

○ Electricity consumption forecast data from the National Energy Basic Plan was applied equally to the 5th BPE.

□ Peak demand forecast

○ The peak demand forecast was calculated by applying the deviation between the electricity consumption forecast from the National Energy Basic Plan and that of the 4th BPE to peak demand forecast data from the 4th BPE.

3) Forecast Results

□ Electricity consumption

○ An average growth rate of 3.1% per annum is expected from 2010 to 2024.

* 425,412GWh in 2010 → 653,541GWh in 2024

- Increase rate by contract classification: 2.7% for residential, 4.6% for commercial and 2.2% for industrial.

Table 2.7 Electricity consumption by contract classification (unit: GWh)

Classification	2010	2015	2020	2024	'10~'24(%)
Residential	75,769	89,870	101,268	110,333	2.7
Commercial	133,735	181,112	223,957	251,156	4.6
Industrial	215,909	249,860	272,996	292,052	2.2
Total	**425,412**	**520,842**	**598,221**	**653,541**	**3.1**

□ Peak demand

○ An average growth rate of 3.1% is expected during the period 2010 ~ 2024.

* 70,457MW in 2010 → 107,437MW in 2024

Table 2.8 Peak demand Forecast (unit: MW)

Year	2010	2015	2020	2024	'10~'24(%)
Peak Demand	70,457	86,754	99,653	107,437	3.1

C. Target Demand Forecast

1) Key Assumptions

□ Setting the "Target Demand" by strengthening demand side management in the electricity sector on the reference demand (BAU) based on the National Energy Basic Plan.

○ Planning and introducing measures such as expanding the distribution of high efficiency apparatus, and rationalizing the electric rate system in order to achieve the target demand.

- Distribution of high efficiency apparatus: expand the distribution of energy high efficiency apparatus and introduce a "turning off standby power" campaign and "efficiency level" scheme by increasing investment in EERS (Energy Efficiency Resource Standard) for energy efficiency improvement.
- Efficiency improvement of energy use: R&D for energy efficiency improvement, energy system innovation of factories and buildings, price reduction for high efficiency lighting apparatus, efficiency standardization for machinery.
- Rationalization of the electricity pricing system: gradually switch over to a rate system by voltage based on supply cost and introduce more flexible pricing based on demand side management, including a customer choice rate system, hourly or real time pricing.

2) Forecast Results

□ Electricity consumption

○ An average growth rate of 1.9% is expected during the period 2010 ~ 2024.

Table 2.9 Consumption forecast (unit: GWh)

Year	2010	2015	2020	2024	'10~'24(%)
Electricity Consumption	423,784	496,590	535,779	551,606	1.9

□ Peak demand

○ An average growth rate of 2.2% is expected during the period 2010 ~ 2024.

Table 2.10 Peak demand forecast (unit: MW)

Year	2010	2015	2020	2024	'10~'24(%)
Peak demand	69,886	80,009	89,225	95,038	2.2

3. Future Supply and Demand Outlook

A. Key Assumptions

□ Electricity Demand: Reference demand and target demand

○ Reference demand: Demand forecast result in case of business as usual scenario

○ Target demand: Target demand set by taking additional measures such as strengthening demand side management, improving energy efficiency, and rationalizing the electricity rate system.

□ Generation capacity: Reference generation capacity planning

○ Installed capacities (as of the end of 2009) are reflected.

○ Retirement intents from 2010 to 2024 are reflected.

○ On the basis of evaluation results on construction intents and reference planning results, new generation capacities are reflected.

* When forecasting supply and demand by region, ATC (Available Transfer Capability) and transfer generating limits of HVDC are considered.

□ Generation capacity criteria

○ For general units, name-plate capacity is reflected

○ For distributed generation (non-dispatchable generation) capacity, only peak-contributing capacities are reflected.

* Installed reserve margin for each year is forecasted as of the end of June of that year.

* Generation outlook by fuel for each year is forecasted as of the end of that year.

Table 2.11 Peak contribution rate for distributed generation systems

Classification	Renewable							RCS*
	Small Hydro	Wind	Solar	Ocean	Biomass/ Waste/ By-product Gas	Fuel Cell/ IGCC	Geother-mal heat	Non dispatchable
Peak Contribution Rate (%)	45.0	24.6	18.0	29.5	39.7	100	90	44.0

※ Peak contribution rate for distributed generation system by fuel is calculated based on ELCC method (probabilistic approach) using past actual generation data.

※KEEI study data is applied for the peak contribution rate of geothermal units.

※ Generators for Residential Commercial Services are hereinafter referred to as the "RCS".

B. Electricity Supply and Demand Outlook

□ Nationwide basis

○ Since the installed reserve margin compared to reference demand is expected to be 3.7 ~ 5.0% until 2013, it is necessary to take more active measures in order to respond effectively in terms of short-term supply and demand.

* Load control program, commissioning generating output, etc.

○ The reserve margin compared to target demand is expected to remain at 13.9~20.4% after 2014, thereby enabling the effective stabilization of supply and demand.

* Installed reserve margin compared to reference demand is expected to be 3.7~10.1% and it is necessary to carry out a demand response program on time as planned.

Table 2.12 Electricity supply and demand outlook by year

Year	Peak Demand (MW)		Total Capacity (MW)		Installed Reserve Margin (%)	
	Target	BAU	Summer	Year-end	Target	BAU
2010	69,886	70,457	73,247 (74,344)	75,415	4.8 (6.4)	4.0 (5.5)
2011	72,620	73,713	77,408	78,957	6.6	5.0
2012	74,414	76,161	79,839	81,713	7.3	4.8
2013	76,207	79,784	82,750	85,945	8.6	3.7
2014	78,017	83,360	88,858	90,869	13.9	6.6
2015	80,009	86,754	92,465	96,283	15.6	6.6
2016	81,988	89,629	98,697	98,837	20.4	10.1
2017	83,913	92,281	100,626	101,311	19.9	9.0
2018	85,810	95,075	101,311	101,568	18.1	6.6
2019	87,607	97,405	102,968	104,097	17.5	5.7
2020	89,225	99,653	106,897	107,285	19.8	7.3
2021	90,713	101,640	108,185	108,570	19.3	6.4
2022	92,111	103,644	110,070	110,457	19.5	6.2
2023	93,598	105,614	111,957	112,294	19.6	6.0
2024	95,038	107,437	112,294	112,593	18.2	4.5

※ Figures in parenthesis are based on the actual availability and operating reserve.

□ Metropolitan area

Table 2.13 Electricity supply and demand outlook for the Metropolitan area

Year	Peak Demand		Generating Capacity (MW)		Transmission Credit (MW)	Total Capacity (MW)		Installed Reserve Margin (%)	
	Target	BAU	Summer	Year-end		Summer	Year-end	Target	BAU
2010	28,056	28,316	16,911	17,073	14,355	31,266	31,428	11.4	10.4
2011	29,052	29,469	18,879	18,921	14,801	33,680	33,722	15.9	14.3
2012	29,795	30,465	18,921	20,435	15,463	34,384	35,898	15.4	12.9
2013	30,579	31,972	20,679	21,546	15,957	36,636	37,503	19.8	14.6
2014	31,358	33,454	24,521	24,971	16,421	40,942	41,392	30.6	22.4
2015	32,193	34,850	24,567	24,577	16,342	40,909	40,919	27.1	17.4
2016	33,016	36,035	24,577	24,577	16,831	41,408	41,408	25.4	14.9
2017	33,819	37,131	24,967	25,215	17,126	42,093	42,341	24.5	13.4
2018	34,594	38,270	25,215	25,215	17,317	42,532	42,532	22.9	11.1
2019	35,329	39,225	25,215	25,215	17,904	43,119	43,119	22.0	9.9
2020	36,023	40,182	25,215	25,215	19,446	44,661	44,661	24.0	11.1
2021	36,661	41,034	25,215	25,215	19,938	45,153	45,153	23.2	10.0
2022	37,230	41,859	25,215	25,215	20,118	45,333	45,333	21.8	8.3
2023	37,746	42,580	25,215	25,215	19,523	44,738	44,738	18.5	5.1
2024	38,191	43,187	25,215	25,215	19,536	44,751	44,751	17.2	3.6

□ Jeju Island

Table 2.14 Electricity supply and demand outlook for Jeju

Year	Peak Demand		Generating Capacity (MW)		Transmission Credit (MW)	Total Capacity (MW)		Installed Reserve Margin (%)	
	Target	BAU	Summer	Year-end		Summer	Year-end	Target	BAU
2010	625	625	691	694	150	841	844	34.6	34.6
2011	627	637	698	714	150	848	1,114	35.2	33.1
2012	650	667	692	699	400	1,092	1,099	68.0	63.7
2013	675	708	644	649	400	1,044	1,049	54.7	47.5
2014	700	750	672	696	400	1,072	1,096	53.1	42.9
2015	728	791	696	719	400	1,096	1,119	50.5	38.6
2016	757	829	719	743	400	1,119	1,143	47.8	35.0
2017	786	866	743	743	600	1,343	1,343	70.9	55.1
2018	817	905	743	743	600	1,343	1,343	64.4	48.4
2019	848	942	743	743	600	1,343	1,343	58.4	42.6
2020	879	980	743	743	600	1,343	1,343	52.8	37.0
2021	911	1,017	743	743	600	1,343	1,343	47.4	32.1
2022	943	1,054	743	743	600	1,343	1,343	42.4	27.4
2023	975	1,091	743	743	600	1,343	1,343	37.7	23.1
2024	1,007	1,126	743	743	600	1,343	1,343	33.4	19.3

C. Generation Capacity Mix Outlook by Fuel Type

□ The share of nuclear, renewable and RCS capacities is expected to increase, while that of coal and LNG is expected to decrease.

* Although 3,000MW of nuclear energy is additionally reflected in the 5th BPE, its share of the total is expected to remain the same as in the 4th BPE.

* The share of oil capacity is expected to decrease continuously, and that of pumped storage capacity is expected to remain the same as the level in 2011.

Table 2.15 Generating capacity mix outlook

(unit: MW, %)

Classification		Nuclear	Coal	LNG	Oil	Pumped Storage	Renewable	RCS	Total
2010	4th BPE	18,716	24,205	19,899	5,383	3,900	2,365	1,668	76,136
		24.6	31.8	26.1	7.1	5.1	3.1	2.2	100
	5th BPE	18,716	24,205	19,422	5,372	3,900	2,127	1,674	75,416
		24.8	32.1	25.8	7.1	5.2	2.8	2.2	100
2015	4th BPE	25,916	29,420	23,062	4,291	4,700	3,384	2,795	93,568
		27.7	31.4	24.6	4.6	5.0	3.6	3.0	100
	5th BPE	24,516	30,945	23,517	4,108	4,700	4,183	4,314	96,283
		25.5	32.2	24.4	4.3	4.9	4.3	4.4	100
2020	4th BPE	31,516	29,420	23,062	4,291	4,700	4,060	3,142	100,191
		31.5	29.4	23.0	4.3	4.7	4.1	3.1	100
	5th BPE	31,516	31,945	23,517	4,108	4,700	6,653	4,846	107,285
		29.4	29.7	21.9	3.8	4.4	6.2	4.6	100
2024	5th BPE	35,916	31,445	23,517	4,108	4,700	8,061	4,846	112,593
		31.9	27.9	20.9	3.6	4.2	7.2	4.3	100

D. Generation Capacity Mix Outlook by Fuel Type

□ As the percentage of nuclear capacity increases, the percentage of nuclear generation is expected to increase by more than 17% (Nuclear contributes approximately 31% as of 2010)

Table 2.16 Generation outlook

(unit: GWh, %)

Year	Nuclear	Coal	LNG	Oil	Pumped storage	Renewable	Total
2010	144,856	193,476	100,690	14,693	2,084	5,949	461,747
	31.4%	41.9%	21.8%	3.2%	0.5%	1.3%	100%
2015	201,089	220,886	89,891	6,795	2,551	20,009	541,221
	37.2%	40.8%	16.6%	1.3%	0.5%	3.7%	100%
2020	259,378	217,454	62,081	3,039	6,256	40,648	588,856
	44%	36.9%	10.5%	0.5%	1.1%	6.9%	100%
2024	295,399	188,411	59,201	2,912	8,202	54,467	608,591
	48.5%	31%	9.7%	0.5%	1.3%	8.9%	100%

※ Coal: Anthracite + Bituminous

※ LNG generation is much more volatile to electricity demand compared to other generation sources.

E. Investment Cost Outlook

□ A total of 49 trillion won is expected to be invested in generation capacity expansion during the period of 2010~2024

Table 2.17 Investment cost outlook

(unit: 100 million KRW)

Year	2010~2014	2015~2019	2020~2024	Total
Nuclear	129,359	164,627	38,231	332,218
Coal	88,209	12,027	0	100,236
Oil	0	0	0	0
LNG	51,008	0	0	51,008
Pumped Storage	2,536	0	0	2,536
Total	271,112	176,655	38,231	485,998

※ Basis of price: Fixed price as of January 2010, excluding investment in renewables/RCS

III. Capacity Expansion Plan

1. Generation Expansion Plan

2. Transmission Expansion Plan

1. Generation Capacity Plan

A. Basic Direction and Planning Principles

1) Basic Direction

□ Establishing an ideal capacity plan (reference plan) taking into consideration the stability of electricity supply and demand and various government policies in order to provide the optimal installed reserve margin and fuel mix.

○ Eco-friendly fuel mix: increasing nuclear and renewable energy to its maximum

○ Least cost electricity supply system: expanding base-load generation (nuclear, coal)

○ Stability of power supply and demand: taking measures against future uncertainty (demand forecast, construction performance)

○ Consistency with other energy plans: maintaining consistency with other energy plans

Table 3.1 Basic direction for the reference plan

Eco-friendly fuel mix	Least cost electricity supply system
Increasing nuclear and renewable energy to its maximum	Expanding base-load generation (nuclear, coal) Stabilizing power market price (SMP)
Stability of power demand and supply	Consistency with other energy plans
Satisfying the reliability standards - LOLP 0.5 day/year - meeting LOLP 0.5 day/year even in cases of a 4000MW excess demand taking into consideration the uncertainty of demand growth	Maintaining consistency with reference demand (BAU) on NEBP and target demand

※ After generating all possible generation capacity mix as of 2024, the final reference plan is induced by analyzing important factors using an energy-planning model (WASP-Ⅳ)

□ Based on the calculated necessary generation capacity, the GenCos' intents for construction are evaluated considering the generation capacity required by fuel; the results are reflected selectively.

○ As a part of the promotion policy, all construction intents for distributed generation systems (renewable and RCS) are reflected without evaluation.

2) Results of Optimal Capacity Planning

□ Generation capacity in the case of a reference plan

○ Generation capacity necessary to construct additional capacity as of 2024

Table 3.2 Generation capacity for reference demands

Nuclear	Coal	LNG	Other
8,600 (6 units)	2,000 (4 units)	2,600 (4 units)	13,200

□ Generation composition ratio

○ Total installed capacity is expected to 112,593MW in 2024.

Table 3.3 Generation capacities composition ratio (based on 2024)

Nuclear	Coal	LNG	Petroleum	Other
32% level	28% level	21% level	4% level	15% level

※ Coal: anthracite + bituminous. Other: hydro + pumped storage + renewables/RCS.

※ For distributed generation (non-dispatchable units) capacity, only peak-contributing capacities are reflected

□ Installed reserve margin by year (%)

○ Installed reserve margin by year is expected to remain at about 14% ~ 24% from 2014 to 2024

Table 3.4 Installed reserve margin by year (unit : %)

2014	2015	2016	2017	2018	2020	2022	2024
13.9	15.6	20.4	19.9	18.1	19.8	19.5	18.2

※ Installed reserve margin is calculated based on target demand

□ Other

○ The total cost for electricity supply is approximately 300 trillion KRW (as of January 2010, the construction cost for incumbent plants is excluded)

B. Surveys on Gencos' Intents for Construction

1) Survey Outline

□ Purpose: The goal of the survey is to reflect the GenCos' intents for construction or retirement.

□ Period: 22 March 2010 ~ 30 April 2010 (40 days)

□ Objects: Capacity plans under construction, new construction and power plant retirement plans.

2) Aggregate data on Power Plant Construction Intents

□ Construction intents covering a total of 48,966MW (excluding renewable, RCS, generators in the island areas)

※ Construction intents for the 3rd BPE: 52,360MW, Construction intents for the 4th BPE: 54,700MW

○ Under construction: 29,976MW (34 units)

○ New intents: 18,990MW (25 units)

- Private GenCos have submitted construction intents for coal fired power plants (4 units of a 500MW level)

Table 3.5 Construction intents by company

(unit: MW)

Classification	KHNP	5 Major* GenCos	Private* GenCos	Total
Under construction (permits ~ commencement of work)	15,200 (12 units)	9,243 (13 units)	5,533 (9 units)	48,966 (59 units)
Under planning	3,000 (2 units)	6,490 (8 units)	9,500 (15 units)	
Total	18,200 (14 units)	15,733 (21 units)	15,033 (24 units)	

※ Major: KOMIPO, KOSPO, KOSEP, WP, EWP

※ Private: STX, Dongbu Construction, Greentech, Songdo Power, Samsung C&T, GS Power, GS EPS, POSCO Power, POSCO Construction, SK E&S, SK Construction

Table 3.6 Submitted GenCos' intents for construction by year

(unit: MW)

Year	Generation Capacity (MW)				
	Nuclear	Coal	CC (Combined Cycle)	Pumped storage	Total
2010	1,000 (1 units)		853 (1 units)		1,853 (2 units)
2011	1,000 (1 units)		1,150 (2 units)	800 (2 units)	2,950 (5 units)
2012	1,000 (1 units)		1,283 (2 units)		2,283 (3 units)
2013	2,400 (2 units)		1,650 (3 units)		4,050 (5 units)
2014	1,400 (1 units)	2,240 (3 units)	7,650 (12 units)		11,290 (16 units)
2015		4,850 (7 units)	1,200 (2 units)		6,050 (9 units)
2016	1,400 (1 units)	4,000 (4 units)	400 (1 units)		5,800 (6 units)
2017	1,400 (1 units)	1,000 (1 units)	750 (1 units)		3,150 (3 units)
2018	1,400 (1 units)	1,740 (2 units)	1,200 (2 units)		4,340 (5 units)
2019	1,400 (1 units)				1,400 (1 units)
2020	1,400 (1 units)				1,400 (1 units)
2021	1,400 (1 units)				1,400 (1 units)
2022	1,500 (1 units)				1,500 (1 units)
2023	1,500 (1 units)				1,500 (1 units)
2024					
Total	18,200 (14 units)	13,830 (17 units)	16,136 (26 units)	800 (2 units)	48,966 (59 units)

※ Construction intents are reflected based on completion year, and Renewables/RCS and all plants on islands are excluded.

3) Aggregate Data on Power Plant Retirement Intents

□ GenCos plan to retire 3,983MW (19 units) from 2010 to 2024.

○ No retirement plan for nuclear and hydro energy

○ 10 steam power units (2,088MW), 5 internal combustion power units (95MW), 4 combined cycle power units (1,800MW)

Table 3.7 Submitted GenCos' intents for retirement by year

(unit: MW)

Year	Retirement Capacity (MW)			
	Steam Power	Internal Combustion	Combined Cycle	Total
2010				0 (0 unit)
2011			450 (1 unit)	450 (1 unit)
2012	200 (1 unit)	40 (4 units)		240 (5 units)
2013	400 (2 units)	55 (1 unit)	450 (1 unit)	905 (4 units)
2014	988 (5 units)		450 (1 unit)	1,438 (6 units)
2015			450 (1 unit)	450 (1 unit)
2016～2020				0 (0 unit)
2021	500 (2 units)			500 (2 units)
2022～2024				0 (0 unit)
Total	2,088 (10 units)	95 (5 units)	1,800 (4 units)	3,983 (19 units)

C. Criteria for Evaluating the Intents for Construction

1) Basic evaluation directions

□ The GenCos' intents for construction are evaluated to establish a generation capacity plan at an optimal capacity as shown in the "Reference generating expansion plan," and the results are reflected selectively.

○ All intents for construction of renewable and RCS are reflected without evaluation in consideration of the promotion policy for the distributed generation systems.

□ Basic evaluation direction

○ Improving the effectiveness of the 5th BPE by evaluating cases of GenCos' construction delays in the previous planning.

○ Increasing the importance of the construction workability factor in the evaluation and subdividing of the evaluation criteria.

2) Projects considered in the plan

Classification for projects to be fixed and projects to be evaluated

Table 3.8 Projects considered in the plan

Classification	Objects
Projects to be fixed	o Capacities under construction o Capacities reflected in the previous plan which - got a business license and can complete construction on time (including construction delays of less than 1 year), or - completed a contract for construction or main equipment (such as a boiler and a turbine)
Projects to be evaluated	o Capacities, excluding projects to be fixed, without significant reasons for disqualification in construction on time such as grid connection, fuel supply, regulation and so on.

3) Criteria for evaluating the intents for construction

□ When there are more construction intents than needed, capacities are selectively evaluated based on the criteria below

Table 3.9 Criteria for evaluating intents for construction

Classification			Weighted Value	
Cost index	Transmission costs	Grid connection costs + system reinforcement costs	20	
	Generation costs	Power plant construction costs + Operation costs		
Workability index	Public Acceptance	Local Government's desire to invite	20	80
		Local residents' acceptance	8	
		Public hearing for local residents	2	
	Location Requirements	Obtain sites for power plants	10	
		Obtain water for power plants	5	
		Obtain fuel for power plants	5	
	Acquiring grid connecting facilities		15	
	Environmental impact assessment		10	
	Extent of project delays		20	
	Promoting private investment		5	
	Unexpected things to consider in evaluating		Committee decision	

□ Stability of mid- and long-term supply and demand shall be preferentially considered in the evaluation of each intent

○ When reviewing the reflected projects for permission to do business, opinions from local government and local residents will be fully considered.

D. Results of the Generation Capacity Plan

1) Criteria for Establishing the Capacity Plan

□ Deriving required capacities (on the reference plan) by fuel based on the forecast demand and establishing a capacity plan taking into consideration the uncertainty in the project being completed on time as planned.

○ The optimal plan is derived taking into consideration the reliability target (LOLP 0.5days/year), eco-friendly generation mix, cost minimization, etc. (establishing capacity plan based on the reference plan)

○ Capacities of annually expected delay are calculated for the 5th BPE by applying the annual average delay rate of projects reflected in the previous BPEs. (Uncertainty in project completion on time is considered)

2) Planning methodology and process

□ GenCos' Construction intents are classified into projects to be fixed or projects to be evaluated, and evaluated based on the evaluation criteria.

○ Classification: fixed (23 units, 20,676MW), evaluated (36 units, 28,290MW)

○ Evaluation: evaluating based on cost index (20%) and workability index (80%) respectively

□ Optimal plan (reference plan) is derived considering LOLP target, eco-friendly generation mix, economic efficiency, etc.

○ Reference plan: nuclear (8,600MW), coal (2,000MW), combined cycle (2,600MW)

□ Capacity plan based on the reference plan is established taking into consideration the factors below

○ Whether there is uncertainty in construction completion on time

- Problems such as complaints from local residents, construction delay of facilities for connection to the grid, and difficulty in acquiring sites leads to difficulty in construction completion on time → lack of generating facilities compared to the plan

○ Reviewing construction delay rate considering original completion days of GenCos' intents and cases of construction delay by fuel

- Analyzing lack of generating capacities by fuel and by year respectively compared to the 1st ~ 4th BPE

□ Establishing a generating capacity plan to secure the required capacities by fuel and by year according to the reference plan.

○ Establishing yearly generating capacity plan by fuel construction delay possibilities, and evaluation results in order to secure the reference capacities

- Ensuring generation capacities in the reference plan and stable supply even during construction delays by more fully reflecting the GenCos' intents

3) Generating Capacities Expansion

□ Amount of added generating capacity (2010 ~ 2024)

○ Out of the capacity (total of 48,966MW) indicated in the intents for construction submitted by GenCos, 43,326MW are finally reflected in the 5th BPE

Table 3.10 Generation capacity additions by fuels

(unit: MW, number of units)

Classification		Nuclear	Bituminous Coal	LNG	Oil	Hydro/ Pumped storage	Total
3rd BPE	'06-'20	9,600(8)	9,980(15)	11,239(19)	258(3)	2,460(9)	33,537(54)
4th BPE	'08-'22	15,200(12)	9,480(12)	10,730(17)	77(1)	840(3)	36,327(45)
5th BPE	'10-'24	18,200(14)	12,090(15)	12,236(19)	-	800(2)	43,326(50)

※ Renewable and small island facilities are excluded from the number of units.

□ Generator retirement (2010~2024): total of 3,983MW (19 units).

4) Grade Classification and Projects to be Reflected

Table 3.11 Grade classification and projects to be reflected

Grade	Projects to be fixed	Projects to be evaluated		Retirement	Others
	Reflected		Not-reflected	Reflected	
2010	Singori #1 (Dec.,1000MW) Youngwol CC (Oct.,853MW)				
2011	Singori #2 (Dec.,1000MW) POSCOPower #5 (Feb.,575MW) POSCOPower #6 (Jun..,575MW) YecheonP/S #1 (Sept.,400MW) YecheonP/S #2 (Dec.,400MW)			Boryeong CC #4 (Sept.,450MW)	
2012	Sinwolseong #1 (Mar.,1000MW) Incheon CC #3 (Dec.,450MW) Oseong CC (Dec.,833MW)			Yeosu thermal #1 (Jan.,200MW) Namjejuinternal #1~4(Jan.,40MW)	
2013	Sinwolseong #2 (Jan.,1000MW) Singori #3 (Sept.,1400MW) Pocheon CC #1 (Dec.,750MW) Bugok CC #3 (Dec.,500MW)	Andong CC (Dec.,400MW)		Yeongnam #1,2 (Jan.,400MW) Jeju GT #3 (Jan.,55MW) Boryeong CC #3 (Oct.,450MW)	
2014	Singori #4 (Sept.,1400MW) Youngheung #5 (Jun.,870MW) Youngheung #6 (Dec.,870MW)	Donghae_private #1 (Dec.,500MW) Ansan CC #1 (Mar.,750MW) Jangheung CC (May,800MW) Munsan CC (Jun.,800MW) Pocheon CC #2 (Sept.,750MW) Chuncheon CC (Oct.,500MW) Seoul CC #1 (Dec., 500MW) Seoul CC #2 (Dec., 500MW) Dongducheon CC #1 (Dec., 750MW) Dongducheon CC #2 (Dec., 750MW)	Bucheon #2 (Jul.,550MW) Songdo CC #1 (Sept.,500MW) Songdo CC #2 (Mar.,500MW)	Woolsan #1~3 (Jan.,600MW) Seoul thermal #4,5 (Dec.,388MW) POSCOPower #1 (Aug.,450MW)	Plants in island 52.8MW (48units) Renewables 19,157MW RCS 4,532MW
2015	Samcheok #1 (Dec.,1000MW) Samcheok #2 (Dec.,1000MW) Dangjin #9 (Dec.,1000MW)	Donghae_private #2 (Apr.,500MW) Dongbu Green #1 (Jun.,500MW) Dongbu Green #2 (Jun.,500MW) Yeosu #1 (Nov.,350MW) POSCOpower #7 (Feb.,600MW) POSCOpower #8 (Aug.,600MW)		POSCOPower #2 (Jan.,450MW)	
2016	Sinwooljin #1 (Jun.,1400MW) Dangjin #10 (Jun.,1000MW)	Sinboryeong #1 (Jun.,1000MW) Tae-an #9 (Jun.,1000MW) Tae-an #10 (Jun.,1000MW)	Ilsan CC #3 (Mar.,400MW)		
2017	Sinwooljin #2 (Jun.,1400MW)	Sinboryeong #2 (Jun.,1000MW)	Pocheon CC #3 (Sept.,750MW)		
2018		Singori #5 (Jun.,1400MW)	Yeongheung #7 (Jun.,870MW) Yeongheung #8 (Dec.,870MW) POSCOpower #9 (Jan.,600MW) POSCOpower #10 (Jul.,600MW)		
2019		Singori #6 (Jun.,1400MW)			
2020		Sinwooljin #3 (Jun.,1400MW)			
2021		Sinwooljin #4 (Jun.,1400MW)		Honam thermal #1,2 (Jan.,500MW)	
2022		Singori #7 (Jun.,1500MW)			
2023		Singori #8 (Jun.,1500MW)			
2024				Plants(47units) in island area 17.9MW	
Total	20,676MW (23units)	22,650MW (27units)	5,640MW (9units)	3,983MW (19units)	

※ Capacity plan for renewable is forecasted and established by reflecting the government's RPS target.

※ Retirement plan for plants in island areas is 17.9MW (47 units) of the total from 2010 ~ 2024.

※ DongbuGreen #1, 2 will be reviewed on its workability in the process of permission to do business.

E. Capacity Plan for Renewable and RCS

1) Capacity Plan for Renewables

a) Basic Direction and Planning Principles

□ Basic Direction

○ All intents for the construction of renewables are reflected in the BPE without an evaluation process

- Facilities under construction, facilities that submitted intents for construction, facilities that obtained licenses to do business from central and local governments

○ As the government decided to introduce RPS (Renewable Portfolio Standard) in 2012, the RPS target will be highly reflected in the 5th BPE.

Table 3.12 RPS target

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Target (%)	2.0	2.5	3.0	3.5	4.0	5.0	6.0	7.0	8.0	9.0	10.0

b) Criteria for Planning Principles

○ As intents from renewable GenCos are mostly for construction within the next 5 years, construction capacities resulting from RPS introduction need to be forecasted for the whole planning period and additionally reflected on the BPE.

○ Considering weighted values or characteristics and recent trends for each energy resource, renewable construction capacities from RPS are forecasted based on the following factors.

- Historical trends: Hydro, LFG, waste
- Project plans: Ocean, wind power from the land (short-term), fuel cells (short-term), IGCC, RDF
- Government policy: Solar
- Energy potential: Offshore wind power
- Developing trends: Wind power from the land (short-term), fuel cells (mid and long-term)

○ Peak contribution rates of renewable shall be reflected.

- As renewable such as solar and wind power depend on natural energy during peak times, the peak contribution rate of renewable is reflected when calculating reserve capacity.

2)Results of Renewable Expansion Plan

a) Status and outlook for renewable expansion

□ Status of renewable capacity

○ Current status of renewable capacity as of December 2009: total of 2,750.9MW.

○ Hydro generating capacity is 1,615MW (58.7%), comprising the biggest share among renewables.

Table 3.13 Status of renewable capacity

(unit: MW)

Classification	Hydro		Wind	Solar	Bio Energy	Waste	By-product Gas	Fuel Cell	Total
	Normal	Small							
As of December 31st, 2009	1,529.9	84.6	345.9	414.7	86.2	36.8	230.3	22.5	2,750.9
	55.6%	3.1%	12.6%	15.1%	3.1%	1.3%	8.4%	0.8%	100%

□ Outlook for renewable expansion

○ Including 8,346.1MW of GenCos' construction intents and 10,811.3MW of additional construction by RPS, a total of 19,157.4MW of new renewable facilities are expected to be constructed during the period from 2010 ~ 2024.

○ The amount of new renewable capacities increases by more than 3 times compared to that of the 4th BPE, and wind power is expected to amount to 8,628.1MW (45%), accounting for the highest share among them.

Table 3.14 Outlook for renewable expansion (2010 ~ 2024)

(unit: MW)

Classification	Hydro	Wind	Ocean Energy	Solar	Bio energy	Waste	By-product Gas	Fuel Cell	Geo-thermal	IGCC /CCT	Total
GenCos' intents	128.7	2,309.7	3,037.5	472.7	240.9	42.6	1,134	80	-	900	8,346.1
Additional generating capacity by RPS	103.8	6,318.4	-	3,340.4	108	329	-	580.5	31.2	-	10,811.3
Total	232.5	8,628.1	3,037.5	3,813.1	348.9	371.6	1,134	660.5	31.2	900	19,157.4

※ Additional generating capacity by RPS is calculated considering government target and energy potential.

b) Summary of Renewable Expansion Plan (2010 ~ 2024)

Table 3.15 Renewable expansion

(unit: MW)

Year	Hydro		Wind Power	Ocean Energy	Solar	Bio energy	wastes	By-product gas	Fuel Cell	Geothermal	IGCC/CCT	Total
	normal	small										
2009. 12 (actual)	1,529.9	84.6	345.9		414.7	86.2	36.8	230.3	22.5			2,750.9
2010. 06		3.1	2.3		136.4	1.1	5.6		1.2			149.7
2010. 12		0.6	113.3		104.4	7		342	20.8			588.1
2011. 06	60	1.1	89.1	254	45.9			142	1.4			593.5
2011. 12		56	394.5		87.7	10	3.2		36.6			588
2012. 06		1	389		2.9		10					402.9
2012. 12			562.5		304.3	4		150	20	0.2		1041
2013. 06			139		3.4	30	3.8	300				476.2
2013. 12		1.7	218		309.7	206	20	200	30.5			985.9
2014. 06			117	50.5								167.5
2014. 12		5.2	95		330.8	6	24.8		50			511.9
2015. 06												0
2015. 12		10.4	95	520	357.8	6	25.9		50		300	1,365.1
2016. 06					72	0.8						72.8
2016. 12		10.4	95		171.4	6	26.9		50	1		360.7
2017. 06				1,320								1320
2017. 12		10.4	34.4	893	247.1	6	28.0		50		300	1,568.9
2018. 06					0.6							0.6
2018. 12		10.4	600		227.2	6	29.0		50			922.6
2019. 06												0
2019. 12		10.4	800		242.9	10	30.1		50	3	300	1,446.4
2020. 12		10.4	1,100		238.5	10	31.1		50	3		1,443
2021. 12		10.4	1,100		211.8	10	32.0		50	5		1,419.1
2022. 12		10.4	1,100		224.6	10	32.9		50	5		1,432.9
2023. 12		10.4	880		238.9	10	33.7		50	6		1,229.0
2024. 12		10.4	704		254.8	10	34.6		50	8		1,071.7
New	60	172.5	8,628.1	3,037.	3,813.1	348.9	371.6	1,134	660.5	31.2	900	19,157.4
Total	1,589.9	257.10	8,974.0	3,037.	4,227.8	435.1	408.4	1,364.3	683.0	31.2	900	21,908.3

※ GenCos' construction intents and additional construction forecast by RPS are included in this renewableexpansion plan.

c) Renewable Generation Outlook by year (2010 ~ 2024)

□ Renewable generation in 2024 is expected to reach 54,467GWh, comprising 8.9% of total generation.

Table 3.16 Renewable generation outlook

(unit: GWh)

Year	Hydro		Wind Power	Ocean Energy	Solar	Bio energy	Wastes	By-product gas	Fuel Cell	Geothermal	IGCC/CCT	Total
	normal	small										
2010	3,074	176	776	0	686	507	55	450	224	0	0	5,949
2011	3,195	180	1,430	478	939	532	55	1,395	425	0	0	8,629
2012	3,195	294	2,997	478	1,236	835	72	1,395	619	2	0	11,123
2013	3,195	294	4,446	478	1,654	2,218	103	2,274	788	2	0	15,452
2014	3,195	298	5,148	573	2,089	2,489	119	2,665	1,058	2	0	17,635
2015	3,195	318	5,609	573	2,553	2,499	152	2,665	1,392	2	1,051	20,009
2016	3,195	339	5,956	1,553	2,959	2,514	186	2,665	1,727	9	2,102	23,205
2017	3,195	360	6,246	4,039	3,290	2,785	222	2,665	2,061	9	3,154	28,026
2018	3,195	381	7,171	5,721	3,610	2,795	259	2,665	2,396	9	4,205	32,407
2019	3,195	402	9,046	5,721	3,928	2,808	297	2,665	2,731	33	5,256	36,081
2020	3,195	423	11,541	5,721	4,252	3,086	337	2,665	3,065	57	6,307	40,648
2021	3,195	444	14,409	5,721	4,556	3,102	378	2,665	3,400	96	6,307	44,272
2022	3,195	464	17,280	5,721	4,850	3,119	420	2,665	3,735	136	6,307	47,892
2023	3,195	485	19,885	5,721	5,163	3,396	463	2,665	4,069	183	6,307	51,533
2024	3,195	506	22,007	5,721	5,496	3,413	507	2,665	4,404	246	6,307	54,467

※ Average capacity factor from 2007 to 2009 by energy source is applied to calculate the generation outlook.

※ Capacity factor for ocean, offshore wind power, and IGCC/CCT is referred to in the data from RPS study result (KERI, 2010).

3) Comparative Table for Renewable Capacities (4th BPE vs. 5th BPE)

Table 3.17 4th BPE vs. 5th BPE

[unit: MW]

Classification	The 4th BPE			The 5th BPE		
1. Planning Period	'08 ~ '22 (15years)			'10 ~ '24 (15years)		
2. Capacity Plan	'08 ~ '10	'11 ~ '15	'16 ~'20	'10 ~ '14	'15 ~ '19	'20 ~'24
· Hydro	27.6	60	0	128.7	51.9	51.9
· Wind	640.8	42	0	2,119.7	1,624.4	4,884
· Ocean	255	573	2,253	304.5	2,733	0
· Solar	985	18.5	4.3	1,325.5	1,319	1,168.6
· Bioenergy	3.1	0	0.8	264.1	34.8	50
· Wastes	20.1	30	0	67.4	139.9	164.2
· By-product gas	550	350	0	1,134	0	0
· Fuel Cell	26.9	16.2	0	160.5	250	250
· IGCC/CCT	0	600	0	0	900	0
· Geothermal	0	0	0	0.2	4	27
· **Total**	**6,456.3**			**19,157.4**		
3. Peak Contribution Rate						
· Small Hydro	62.2%			45.0%		
· Wind	21.9%			24.6%		
· Solar	42.8%			18.0%		
· Bioenergy /Wastes /By-product gas	40.9%			39.7%		
· Ocean	30.0%			29.5%		
· Geothermal	-			90.0%		

4) RCS Facilities Expansion Plan

a) Status of RCS facilities

□ A total 31 units of RCS (general type) are currently operating in 21 plant sites as of December 2009.

Table 3.18 Status of RCS facilities

Classifications	Number of companies	Number of sites	Number of units	Generating capacity	
				Central	Non-central
RCS (general type)	15	21	31	977.3MW	632.9MW

※ RCS (CES type) is excluded in the planning from the 5th BPE.

□ RCS facilities expansion outlook (2010 ~ 2024)

○ A total of 4,531.6MW new RCS facilities are expected to be constructed during the period 2010 ~ 2024.

- It has been increased by 1.5 times compared to the 4th BPE (3,128.6MW).

Table 3.19 RCS facilities expansion outlook

Classifications	Metropolitan	Non-metropolitan	Total
Number of companies	12	13	23
Capacity (MW)	2,525.5	2,006.1	4,531.6

F. Electricity Supply and Demand in the Island Areas

1)Status of supply and demand in the Island Areas

□ Overview

○ Currently, the number of islands having self-generating plants are 132, including 63 operated by KEPCO, 25 by local governments, and 44 by local residents

○ Electricity in the Island Areas is generated mostly by diesel engine generators and partially by solar energy.

□ Demand

○ Difficult to forecast due to high demand volatility.

- As a small-scale system, it is sensitive to small load variation and electricity demand can skyrocket with new large-scale load addition.

▪ Ulneungdo is the island with the largest capacity totaling 13,200kW

▪ Janggodo is the island with the smallest capacity totaling 450kW

○ Electricity demand has increased rapidly due to the recent rise in electricity demands created by air-conditioning and heating, and the construction of fish factories and tourist accommodation.

Table 3.20 New large-scale load

Island name	Functions	Capacity (kW)	Year
Paikryungdo	Air-conditioning & heating (16)	4,510	2010
Yeonpyeongdo	Air-conditioning & heating (11)	1,825	2010
Duckjukdo	Air-conditioning & heating	800	2010
Seungbongdo	Air-conditioning & heating	500	2010
Ulneungdo	Exploiting deep water (2)	3,000	2010
	Accommodation	700	2010
	Fish factory	1,000	2010
	Accommodation	1,000	2011
	Monorail	700	2011
	Tourist facility	500	2012
Chujado	Fish factory	1,000	2011
	Desalination facility	500	2012

□ Supply Status

○ Plant site saturation

- Lack of space for additional facility construction except Ulneungdo, Yeonpyeongdo, and Jodo among islands with over 200 households
- Since it is difficult to secure new sites, the capacity plan needs to consider that new plants should be built on existing sites, thereby replacing old plants.

○ A high reserve margin is necessary to secure operating reliability.

- Acquiring a sufficient reserve margin taking into consideration any unexpected outages and preventive maintenance of the small number of generators covering high demand.

Table 3.21 Generation capacity

No. of plant units	No. of islands	Average reserve margin for 2010 ~ 2014 (%)
3	5	292.44
4	10	94.30
5	4	92.52
6	2	41.91
7	1	43.23
8	2	35.67

2)Planning Criteria

□ Scope

○ The scope of islands for planning was expanded from 15 islands over 300 households in the 4th BPE to 25 islands over 200 households in the 5th BPE.

□ Period

○ 2010 ~ 2014 (5 years)

□ Criteria for the adequate reserve margin

○ Based on the total number of plant units and capacity, an adequate installed reserve

margin will be applied discretely in order to secure a stable supply even in situations of maximum generator outage.

○ The scale of expansion is decided based on the demand forecast for 5 years forward so that no more new generators would be added during this period to avoid inefficiency from frequent plant construction on the same island.

Table 3.22 Generation capacity

No. of plant units	Reference reserve margin	Additional application according to capacity composition		
		1 unit (2 times)	2 units (2 times)	other
3	55% ~	30% *1)	15% *2)	Proportionally applied
4	38% ~	15%	10%	
5	30%	[Maximum unit of capacity + 5%] is applied as a standard reserve margin		
6-8	25%			

※ 1. Plant composition (3 units, 150kW, 150kW, 300kW): 55%(standard) + additional 30%

※ 2. Plant composition (3 units, 150kW, 300kW, 300kW): 55%(standard) + additional 15%

※ Based on the 2008 research results of optimal demand forecasts about islands not connected to the mainland power system.

□ Standard for plant retirement

○ Plants' life span is applied as 15 ~ 25 years according to the engine cycle.

Table 3.23 Standard for plant retirement

Classification	Low speed engine	Middle speed engine	High speed engine
Life span (year)	25	20	15
Cycle (rpm)	Less than 300	300 ~ 1000	More than 1000

3) Generation Expansion Plan

□ Peak demand outlook by year

○ Demand of 25 islands for 5 years is expected to increase 5.7% per year.

○ Demand forecast methodologies

- Peak demand scenario 1 is generated by analyzing the historical trend of actual peak demand.

- Peak demand scenario 2 is generated by using load forecasting data and consumption forecasting data
- Peak demand is forecasted by averaging scenario 1 and 2, and 50% of the willingness of new contract demand is additionally reflected in the forecasted peak demand.

Table 3.24 Peak demand

[unit: kWh]

Island	Peak Demand					Average Increase Rate (%)
	2008	2009	2010	2011	2012	
Paikryungdo	7,952	8,624	8,945	9,274	9,612	4.9
Daecheongdo	1,587	1,773	1,915	2,061	2,213	8.7
Yeunpyeongdo	3,527	3,905	4,318	4,769	5,261	10.5
Dukjukdo	1,920	1,970	2,029	2,101	2,190	3.4
Jawoldo	855	958	1,062	1,178	1,306	11.2
Sungbongdo	1,228	1,288	1,353	1,406	1,457	4.4
Sochungdo	1,227	1,311	1,400	1,497	1,602	6.9
Uechungdo	613	695	789	895	1,013	13.4
Sapsido	585	622	660	699	738	6.0
Oiyeundo	285	310	337	367	400	8.9
Wido	976	982	980	970	953	-0.6
Hongdo	933	1,031	1,113	1,149	1,185	6.2
Gageodo	599	744	830	908	995	13.7
Jodo	1,435	1,494	1,550	1,581	1,612	3.0
Ulneungdo	11,665	13,965	15,970	16,590	17,253	10.5
Chujado	3,318	4,007	4,458	4,669	4,890	10.4
Gaeyado	573	568	552	523	482	-4.2
Jodo	235	254	258	263	267	3.3
Geomundo	1,903	1,996	2,063	2,130	2,195	3.6
Yeojado	110	110	110	109	109	-0.2
Janggodo	222	246	265	286	309	8.6
Huksando	2,324	2,333	2,395	2,396	2,385	0.7
Nagwoldo	157	166	165	163	161	0.6
Sidando	174	183	188	192	197	3.1
Average rate						5.7

□ Generator construction and retirement (2010 ~ 2014)

○ New construction (Total of 48 units, 52,750kW)

○ Existing generator retirement (total of 47units, 17,900kW)

Table 3.25 Construction and retirement

[unit: kW]

Classification	2010	2011	2012	2013	2014	Total
Construction	5,450	14,300	18,400	1,600	13,000	52,750
Retirement	1,550	2,250	7,500	650	5,950	17,900

□ New construction cost (2010 ~ 2014)

○ The total cost for new construction from 2010 ~ 2014 is expected to reach approximately 80 billion won.

Table 3.26 New construction cost

[unit: billion KRW]

Classification	2010	2011	2012	2013	2014	Total
Construction	8.3	21.7	27.9	2.4	19.7	80

2. Transmission and Distribution System Plan

A. Long-term Standard Plan Criteria

1) Basic Directions

□ Role of network systems classified by voltage level

- ○ 765kV: delivers electricity from large-scale generation complexes to congested load centers.
- ○ 345kV: builds an inter-regional network or a bulk power source in city areas.
- ○ 154kV: builds the intercity network within the 345kV-supplied areas or works as the supply source for electricity distribution.
- ○ 66kV: construction of any new line shall be minimized with flexibility.
- ○ 22.9kV: delivers electricity from the 154kV substations to general customers.

□ Security of adequate network reliability

- ○ Prepare for the locating of transmission lines and substations in advance and expand transmission facilities at a suitable time.
- ○ Strengthen the linkage between the generation expansion plans and transmission facilities construction plans as well as the stability of the power system in metropolitan areas and Jeju Island.

□ Harmony of supply reliability and economical efficiency

- ○ Minimize Transmission and Distribution (T&D) loss and congestion costs to promote the efficiency of investment in transmission facilities.
- ○ Minimize power supply interruption in case of outages of the transmission system.
- ○ Improve techniques for evaluating the economic value of the transmission system and introduce supply reliability evaluation techniques.

□ Improving the stability of the transmission system

- ○ Enhance the stability of a large-scale transmission system: Introduce new technologies such as flexible AC transmission system (FACTS).
- ○ Minimize fault current: upgrade rated short circuit breaking circuits, installation of serial reactors, BTB (Back-to-Back) installation, bus split, and transmission lines off, etc.
- ○ Balance reactive power supply and demand: install power condensers, shunt reactors and static var compensators, deploy distributed generations, and switch off the transmission lines under light load conditions, etc.

2) Criteria for Transmission and Distribution System Expansion

□ Reliability Limit in Contingencies

Table 3.27 Reliability Limit in Contingencies

Contingency Conditions	Overload Factor	Extent of Failure	Available Steps After a Fault
・One line of the 345kV system connected to the power plant ・1 Bank of the 345㎸ main transformer	Prohibit overload (at nominal capacity).	・Prohibit load drop. ・Prohibit generator drop out.	・Prohibit adjustment of generation power.
・One line of the 154kV system connected to the power plant	Allow temporary overload.	・Prohibit load drop. ・Prohibit generator drop out.	・Allow adjustment of generation power.
・One line of the main system below 345kV ・One line of the load supply system below 345kV	Allow temporary overload.	・Prohibit load drop. ・Prohibit generator drop out.	・Allow adjustment of generation power. ・Allow load cutoff.
・1 Bank of 154kV main transformer	Allow temporary overload.	・Allow temporary load drop (note 1). ・Prohibit permanent load drop (note 2).	・Allow load cutoff.
・Two lines of the load supply system below 345kV ・Two lines of the 154kV main system	Allow temporary overload.	・Allow temporary load drop (note 1). ・Prohibit permanent load drop (note 2). ・Allow generator drop out.	・Allow load cutoff.
・Two lines of the 345kV main system ・One line of the 765kV main system	Allow temporary overload.	・Prohibit load drop. ・Prohibit generator drop out.	・Allow adjustment of generation power.
・One line of the 765kV system connected to the power plant ・Two lines of the system connected to power plants below 345kV	Allow temporary overload.	・Prohibit load drop. ・Allow generator drop out.	・Allow adjustment of generation power.

※ 1. A temporary load drop is defined as a condition wherein the power supply can be restored in a short period following an interruption using means such as a load reallocation to other substations without repairing the facilities that failed.

※ 2. A permanent load drop is defined as a condition wherein power supply cannot be restored following an interruption using means such as load reallocation to other substations without repairing the facilities that failed.

□ Power plant interconnection to the power system

○ Interconnection principles: decided by the contract between the generation company and the transmission company based on 『Provision for transmission facilities use』

○ Criteria for power plant interconnection to the power system

- below 1,000MW: 345kV or 154kV.

- over 1,000MW: over 345kV.

- In principle, a power plant should be interconnected with more than two lines.

(One line interconnection is available only when the system is not greatly influenced and the generation company wants it.)

- Interconnection lines should be more than two lines in case the system could not satisfy the power system planning criteria, such as the transient stability problem which occurs with system failure.

□ Criteria for the construction of a transmission system

○ Standard for reinforcing 765kV transmission

- 765kV shall be installed in case the transmission efficiency is more than that of 345kV and a large-scale interchange of electricity is in demand.

- 765kV shall be expanded to maintain its capability considering only n-1 contingency.

○ Standard for reinforcing 345kV transmission

- 345kV shall be installed when it is more appropriate than 154kV when a large increase in demand is expected or the interchange and supply of electricity is not enough with new 154kV lines.

- In principle, construction of new overhead lines is 2 lines (1 route), and the supporting structure is selected by considering the change of long-term power system.

- Subtransmission systems consider route failure, while radial systems and underground systems consider n-1 contingency.

○ Standard for reinforcing 154kV transmission

- 154kV shall be installed if the interconnection is required with the power plant, 345kV and 154kV, or if an over-load occurs at existing substations due to the generation capacity and power demand increase.

- 154kV shall form a multi-system (about 800MW load supply) itself for a 345kV unit.

- In principle, 2π branch off for the existing lines, and 1π branch off for only no problems in load characteristics, short circuit currents, overloads, and system

maintenance.

- 345kV substation network should be configured if possible by the size of 410mm^{2}x2B (underground over 2000mm^2) considering the regional power flow.
- Underground lines should be configured by the largest scale taking into consideration the increasing load demand, and regional networks close to city areas should be configured by installing power tunnels depending upon the power system expansion.
- Main lines such as regional networks supplied by a 345 kV substation will take into account route failures, while other lines and underground lines are expanded taking into consideration the n-1 contingency.

□ Criteria for expanding a substation

○ Extra high voltage substations

- In principle, the final size of extra high voltage transformers is 4 Banks and the number of initial Bank is decided depending upon load supply and economic efficiency.

- 765kV substations shall be installed where the transmission requirement is more than 345kV or a large-scale interchange of electricity is in demand.

- 345kV substations shall be installed in regions requiring additional installation to the existing substation with 3 Banks taking into consideration future load demand increases.

- Transformers shall be extended in case 1 Bank fails and the other Bank exceeds the normal supply capacity.

(Decided considering the interconnected transmission line states between substations.)

○ 154kV substations

- In principle, the final size of 154kV transformers is 4 Banks and the number of initial Bank is decided considering load supply and economic efficiency.

(The final Banks is installed considering the future load increase and the overall economic values of transmission and distribution lines.)

- 154kV substations shall be installed in case an overload occurs at existing substations and demand increases due to the development of an industrial complex or a new city.

- 154kV transformers shall be extended in case 1 Bank fails and the other Bank exceeds the supply capacity. (Decided taking into consideration the conditions of the switch of the load from one distribution line to the other.)

□ Criteria for expanding a distribution line

○ Distribution line capacity

Table 3.28 Distribution line capacity

Type	Standard Capacity (kW)	Capacity per line (kW)		Maximum available circuit-km(length)
		Regular	Irregular	
General lines	10,000	10,000	14,000	33km
		12,000	14,000	Winter (Dec.~Feb.)
High capacity lines	15,000	15,000	20,000	30km

○ Distribution line interconnection

Table 3.29 Distribution line interconnection

Type		Major city, Main street, Housing area	Small and medium-sized city, Outskirts area	Other regions
Interconnection Criteria		Multi-division more than 3 interconnections	More than 3 interconnections	More than 3 interconnections
General Lines (Main line criteria)	Overhead	ALOC 160mm^2	ALOC 160mm^2	ALOC 160mm^2
	Underground	CNCV 325mm^2	CNCV 325mm^2	CNCV 325mm^2
High Capacity Lines (Main line criteria)	Overhead	ALOC 240mm^2	ALOC 240mm^2	ALOC 240mm^2
	Underground	CNCV 325mm^2 (Power tunnel)	CNCV 325mm^2 (Power tunnel)	CNCV 325mm^2 (Power tunnel)
Circuit Breaker Install Criteria (Main line)	Overhead	1km / unit	2km / unit	4km / unit
	Underground	0.5km / unit	1.0km / unit	2.0km / unit

○ Install a new distribution line

- If the maximum load in a distribution line is over the regular operating capacity.
- If the reinforcement of the system is needed when the existing line could not maintain the power quality criteria.
- if a new line installment is needed to serve new customers with bulk power contracts over 5,000kW.
- If a new power supply is needed for a newly developed region such as housing areas and large-scale industrial complexes.

B. Long-term Transmission and Distribution Line Plan[1)]

□ Transmission and Distribution Line

○ Total length of transmission lines: 1.27 times longer in 2024 compared to 2009

○ Total length of distribution lines: 1.08 times longer in 2024 compared to 2009

○ Share of underground lines: 8.9% (2009) → 12.0% (2024)

Table 3.30 Transmission and distribution line

(unit: C-㎞)

Voltage		2009 (actual)		2013		2018		2024	
765㎸	Overhead	755	755 (0.3%)	1,016	1,016 (0.4%)	1,024	1,024 (0.4%)	1,894	1,894 (0.7%)
345㎸	Overhead	8,314	8,551 (3.6%)	9,353	9,690 (3.8%)	9,550	9,962 (3.8%)	9,612	10,034 (3.8%)
	Underground	237		337		412		422	
154㎸	Overhead	18,040	20,469 (8.5%)	19,757	23,038 (9.2%)	20,958	24,706 (9.5%)	21,739	25,883 (9.8%)
	Underground	2,429		3,282		3,748		4,144	
22.9㎸	Overhead	175,943	209,631 (87.6%)	178,650	217,998 (86.6%)	180,183	223,829 (70%)	180,388	225,485 (85.7%)
	Underground	33,688		39,348		43,646		45,097	
Total	Overhead	203,052	239,406	208,776	251,742	211,715	259,521	221,633	263,296
	Underground	36,354		42,966		47,806		49,663	

□ Number of substations

○ Total number of substations: 1.3 times more in 2024 compared to 2009 (from 705 to 920 substations)

○ Total number of substations planned: about 215 over 15 years beginning in 2010

Table 3.31 Number of substations

(unit: stations)

Voltage	2009(actual)	2013	2018	2024
765㎸	6	8	10	12
345㎸	86	99	104	106
154㎸	613	689	755	802
Total	705	796	869	920

1) This plan was described in December 2010, and can be modified until the long-term transmission system plan is defined early in 2011

□ Capacity of substations

○ Share of extra high voltage substation is 55.2% in 2024 compared to 52% in 2009

○ Capacity of substation: 1.31 times larger in 2024 compared to 2009

Table 3.32 Capacity of substations

(unit: MVA)

Classification		2009 (actual)	2013	2018	2024
Capacity (MVA)	765㎸	24,114	33,114	39,114	49,114
	345㎸	104,595	120,095	127,595	130,595
	154㎸	118,643	130,223	139,623	145,323
	Total	247,352	283,432	306,332	325,032

C. Direction and Planning of Transmission and Distribution Line Expansion

□ The transmission owner should establish a detailed long-term transmission and substation expansion plan based on the primary criteria on the basic electricity supply plan and obtain approval from the government within 3 months of the implementation of the confirmed basic long-term electricity supply plan.

□ The confirmed transmission and substation plan can be modified or added to by the transmission owner only under the following situations:

○ In case of changes in power plant construction plans or in demand

○ In case of unavoidable circumstances such as control of the fault current or system voltage level, etc.

○ In case inevitable modification is required for the ongoing project

□ In case the relocation of existing transmission lines is required by public services, the transmission owner is entitled to invoke the Power Resources Development Law after establishing an internal review committee to acquire land for transmission facilities unless the transmission operator and the land owner enter into an agreement for the land.

□ The transmission owner promotes details of the plan according to the Power Resources Development Law procedures in consideration of the cost required, so that the transmission owner can acquire the right of existing land for transmission lines.

D. Construction List of Connection System by GenCos

☐ Reflect the opinion of operators in completion date discord

Table 3.33 Connection plan

Power Plant Name	Capacity [MW]	Connection Plan		Completion Date			Note
		Connection Point	Line Length	Generation System	Connection System		
					KEPCO	Operator	
Pocheon C/C #1,2	750x2	345kV Sinpocheun S/S	Overhead 4.9km	’13.12	’16.05	’13.12	Generation company will build the connection line by itself
Ansan C/C	750	154kV Moknae S/S 154kV Banwall S/S	Moknae S/S: Underground 1.5km Banwall S/S: Underground 4.3km	’14.03	’15.05	’13.09	
Chuncheon C/C	500	154kV Namchuncheon S/S	Underground 3km	’14.10	’15.05	’14.03	
Posco Power #7,8	600x2	345kV Incheon T/P 154kV Posco Power	Inchen T/P: Underground 1.1km 154kV Posco Power: Inside	’15.02	’16.05	’13.12	
Munsan C/C	800	345kV Sindeokeun T/L	Overhead 0.5km	’14.06	’16.05	’13.01	
Jangheung C/C	800	345kV Yangju S/S	Overhead 0.3km Underground 0.5km	’14.05	’16.05	’13.08	
Osung C/C	800	154kV PeungTaek S/S	Overhead 2.2km	’12.12	’15.05	’12.03	
Dongducheon C/C #1,2	750x2	345kV Sindeokeun S/S ~ Sinpochen S/S T/L	Overhead 5.5km	’14.12	’16.05	’14.03	
Boogok C/C #3	500	345kV Sindangjin S/S	Overhead 30km	’13.12	’16.05	’13.12	
Donghae Private #1,2	500x2	345kV Donghae S/S	Underground 8km	’14.12	’16.05	’14.06	

IV. Demand Side Management Plan

A. Basic Directions

□ Reinforcement of the load management plan for the stability of electricity supply for a short-term period from 2010 to 2013

□ Needs for load management will decrease for a long-term period after 2014

□ Expand efficiency management plans such as EERS (Energy Efficiency resources Standard)

B. Main Issues

□ Reinforcement of the load management plan to meet the reasonable electric power reserve margin from 2010 to 2013

○ Enhancement of the load management plan which is effective in reducing peak loads for the stability of the electricity supply while the installed reserve rate is expected within 10% over the short-term from 2010 to 2013

○ More frequent abnormal high temperatures in summer and abnormal cold spells in winter due to recent changes in climate

□ Changes in the load management program due to smart grid implementation

○ Reduction in the ‘designated term’ program and dealing with emergency cases in electricity supply by securing demand resources with ‘weekly notice and previous day notice’

○ More efficient load shift is expected by smart grid implementation

□ Expansion of the efficiency enhancement program

○ The investment in an efficiency enhancement program should be remarkably increased in tandem with the implementation of EERS introduced and promoted by the government.

○ Due to changes in the consumption share of residential and commercial vs. industrial customers (49%:51% in 2010 → 55%:45% in 2024), the need for residential and commercial program expansion has increased.

C. Target Amount of Load Management

□ Methods of target amount calculation

○ Target amount calculation of efficiency enhancement and load management equipment
⇒ Reflect to load forecasting

○ Calculate the target amount of load management considering the load forecast and generation construction plan

※ appropriate amount of demand side management: about 5% of the maximum load

> ☞ Load management is about 5% of maximum load
> Source: [Study for establishing a long-term management plan for long-term and mid-term policy making for load management and efficiency plans (2008.03)]

□ Calculation of load management target amount

Table 4.1 Load management target

(unit: MW)

Year	Maximum Load	5% of Maximum Load	Target Amount
2010	69,886	3,535	3,535
2011	72,620	3,631	3,631
2012	74,414	3,721	3,721
2013	76,207	3,810	3,810
2014	78,017	3,901	3,901
2015	80,009	4,000	4,000
2016	81,988	4,099	4,099
2017	83,913	4,196	4,196
2018	85,810	4,291	4,291
2019	87,607	4,380	4,380
2020	89,225	4,461	4,461
2021	90,713	4,536	4,536
2022	92,111	4,606	4,606
2023	93,598	4,680	4,680
2024	95,038	4,752	4,752

※ Suppressed peak load including efficiency enhancement is reflected in the maximum load

D. Target Amount of Efficiency Enhancement

□ Methods of target amount calculation

○ Highly efficient equipment target amount: estimate the supply change amount following the change in subsidy

- Use the potential amount model: scenario for making up the investment difference

※ Estimate the achievable potential using the future supply rate and payback

> ☞ Achievable potential estimation
> Achievable potential is available following the estimation of the supply rate when the support rate is constant by the equipment investment difference (incremental cost) after calculating the current payback rate by the rebate scenario adoption rule (formation of functions by payback) (supporting 20%~40%)

○ Standby power / Efficiency ranking target amount

- Measure operating power / standby power using power measurement equipment (Wattman)

- Estimation of the total increase of highly efficient equipment sales

Table 4.2 Increase rate of highly efficient equipment sales

’09 ~ ‘11	`12 ~ `14	`15 ~ `17	`18 ~ `20	`21 ~ `24
5.0%	4.5%	4.0%	3.5%	3.0%

□ Calculation of efficiency enhancement target amount

Table 4.3 Efficiency enhancement target

(unit: MW)

Type	2010	2015	2020	2022	2024
Highly efficient equipment	95	949	2,798	3,889	5,127
Standby power / Efficiency ranking	291	1,308	1,744	1,914	2,076
Total	386	2,257	4,542	5,803	7,203

※ Suppressed peak load amount in 2022 on the 4th BPE: 9,068MW (3,265MW decrease)

E. Demand Side Management Investment

(Load Management, Efficiency Enhancement)

□ Investment of 3,959.3 billion won is expected from 2010 to 2024

Table 4.4 Demand side management investment

(unit: billion KRW)

Year	2010	2015	2020	2022	2024	Total
Load management	78.9	90.7	94.8	97.2	99.7	1387.6
Efficiency enhancement	34.6	97.4	239.4	314.9	380.9	2,571.7
Total	113.5	188.1	334.2	412.1	480.6	3,959.3

※ Only the subsidy is calculated, estimated with a constant price of current unit cost (excludes the reasonable energy consumption plan)

V. Future Directions

1. Reinforcement of Reliable Electricity Supply and Demand

□ Unstable factors for electricity supply

- ○ Deepened civil complaints at the locations of generators and transmission lines
- ○ Increases in the different compensation demands for construction sites
- ○ Increased uncertainty in power demand

□ Measures

- ○ Review the introduction of a supply and demand balance system by regional groups (customer responsibility system)
- ○ Review the introduction of a locational pricing system (enlargement of the support fund)
- ○ Introduce a risk management measure and a conservative assessment of load management effects

2. Implementation of the Environment-friendly Resources for a Low-carbon Green Growth System

□ Current State

- ○ Discordance between “Renewable energy” resources and carbon reduction effects
- ○ Insufficient suggestions for the carbon reduction target in an electricity part (adjustment with the basic energy plan)
- ○ Indefinite measurement of effectiveness of the demand management program results

□ Measures

- ○ Reclassify the renewable energy resources reflecting the low-carbon effects
- ○ Institutionalize an active participation in establishing the basic energy plan
- ○ Assess the low-carbon effects of each load management program

3. Electricity Supply Plan Reflecting the Smart Grid System

□ Current State

○ Expected to commercialize the smart grid until 2020

○ Introduce new technologies that largely affect the electricity supply system, such as electric vehicles and demand responses

○ Possibility of paradigm change in current electricity supply system such as micro grid

□ Measures

○ Define an electricity supply model of the smart grid

○ Design the concept of the micro grid

4. Establishing a Permanent Expert Committee Relating Electricity Supply and Continuing the Study

□ Current Status

○ Constitute a related committee while establishing a basic electricity supply plan every 2 years

○ Insufficient optimal future planning and related data collection by forecasting 15 to 20 years ahead

□ Measures

○ Establish permanent organizations with related study (generation capacity planning subcommittee, load forecasting subcommittee, load management subcommittee, and transmission system planning subcommittee, etc)

○ Construct the related data for load forecasting and power supply resources (generation and transmission technology)

○ Continue the related technical studies with an optimization model, demand forecasting methodology, and evaluation and analyzing methodology for demand side management

[Appendix]

1. **Electricity Demand Outlook**

2. **Generation Capacity Mix Outlook by Fuel Type**

3. **Generation Outlook by Fuel Type**

4. **Generation Capacity Expansion and Retirement**

5. **Renewable and RCS Capacity Expansion Plan**

6. **Electricity Supply and Demand in the Island Areas**

7. **Major Transmission Capacity Facilities Plan**

8. **Demand Side Management**

1. Electricity Demand Outlook

A. Reference Demand

Year	Electricity Sales		Peak Load		Load Factor (%)
	GWh	Increase Rate (%)	MW	Increase Rate (%)	
2009 (actual)	394,475	2.4	66,797	6.4	74.1
2010	425,412	7.8	70,457	5.5	74.6
2011	443,786	4.3	73,713	4.6	74.4
2012	462,091	4.1	76,161	3.3	75.1
2013	482,400	4.4	79,784	4.8	74.8
2014	502,613	4.2	83,360	4.5	74.6
2015	520,842	3.6	86,754	4.1	74.3
2016	536,092	2.9	89,629	3.3	74.0
2017	550,527	2.7	92,281	3.0	73.9
2018	567,175	3.0	95,075	3.0	73.8
2019	582,461	2.7	97,405	2.5	74.0
2020	598,221	2.7	99,653	2.3	74.3
2021	612,289	2.4	101,640	2.0	74.5
2022	626,427	2.3	103,644	2.0	74.8
2023	640,297	2.2	105,614	1.9	75.0
2024	653,541	2.1	107,437	1.7	75.3
‘10～’24	-	3.1		3.1	

B. Target Demand

Year	Electricity Sales		Peak Load		Load Factor (%)
	GWh	Increase Rate (%)	MW	Increase Rate (%)	
2009 (actual)	394,475	2.4	66,797	6.4	74.1
2010	423,784	7.4	69,886	4.6	74.9
2011	441,926	4.3	72,620	3.9	75.2
2012	457,570	3.5	74,414	2.5	76.1
2013	471,996	3.2	76,207	2.4	76.6
2014	485,051	2.8	78,017	2.4	76.9
2015	496,590	2.4	80,009	2.6	76.8
2016	506,482	2.0	81,988	2.5	76.4
2017	515,591	1.8	83,913	2.3	76.1
2018	523,867	1.6	85,810	2.3	75.5
2019	531,261	1.4	87,607	2.1	75.0
2020	535,779	0.9	89,225	1.8	74.3
2021	540,078	0.8	90,713	1.7	73.6
2022	544,153	0.8	92,111	1.5	73.1
2023	547,997	0.7	93,598	1.6	72.4
2024	551,606	0.7	95,038	1.5	71.8
’10 ~’24	-	1.9	-	2.2	-

2. Generation Capacity Mix Outlook by Fuel Type

□ Nationwide

[unit: ㎿, %]

Year	Nuclear	Bituminous Coal	Anthracite	LNG	Oil	Pumped storage	Renewable	RCS	Total
2009	17,716	23,080	1,125	17,850	5,368	3,900	1,891	1,255	72,185
	24.54%	31.97%	1.56%	24.73%	7.44%	5.40%	2.62%	1.74%	100.00%
2010	18,716	23,080	1,125	19,422	5,372	3,900	2,127	1,674	75,416
	24.82%	30.60%	1.49%	25.75%	7.12%	5.17%	2.82%	2.22%	100.00%
2011	19,716	23,080	1,125	20,122	5,384	4,700	2,531	2,299	78,957
	24.97%	29.23%	1.42%	25.48%	6.82%	5.95%	3.21%	2.91%	100.00%
2012	20,716	23,080	1,125	21,405	5,154	4,700	2,906	2,627	81,713
	25.35%	28.25%	1.38%	26.20%	6.31%	5.75%	3.56%	3.21%	100.00%
2013	23,116	23,080	1,125	22,205	4,700	4,700	3,384	3,635	85,945
	26.90%	26.85%	1.31%	25.84%	5.47%	5.47%	3.94%	4.23%	100.00%
2014	24,516	24,820	1,125	23,967	4,108	4,700	3,575	4,058	90,869
	26.98%	27.31%	1.24%	26.38%	4.52%	5.17%	3.93%	4.47%	100.00%
2015	24,516	29,820	1,125	23,517	4,108	4,700	4,183	4,314	96,283
	25.46%	30.97%	1.17%	24.42%	4.27%	4.88%	4.34%	4.48%	100.00%
2016	25,916	30,820	1,125	23,517	4,108	4,700	4,320	4,331	98,837
	26.22%	31.18%	1.14%	23.79%	4.16%	4.76%	4.37%	4.38%	100.00%
2017	27,316	30,820	1,125	23,517	4,108	4,700	5,394	4,331	101,311
	26.96%	30.42%	1.11%	23.21%	4.05%	4.64%	5.32%	4.27%	100.00%
2018	27,316	30,820	1,125	23,517	4,108	4,700	5,651	4,331	101,568
	26.89%	30.34%	1.11%	23.15%	4.04%	4.63%	5.56%	4.26%	100.00%
2019	28,716	30,820	1,125	23,517	4,108	4,700	6,265	4,846	104,097
	27.59%	29.61%	1.08%	22.59%	3.95%	4.52%	6.02%	4.66%	100.00%
2020	31,516	30,820	1,125	23,517	4,108	4,700	6,653	4,846	107,285
	29.38%	28.73%	1.05%	21.92%	3.83%	4.38%	6.20%	4.52%	100.00%
2021	32,916	30,320	1,125	23,517	4,108	4,700	7,038	4,846	108,570
	30.32%	27.93%	1.04%	21.66%	3.78%	4.33%	6.48%	4.46%	100.00%
2022	34,416	30,320	1,125	23,517	4,108	4,700	7,425	4,846	110,457
	31.16%	27.45%	1.02%	21.29%	3.72%	4.26%	6.72%	4.39%	100.00%
2023	35,916	30,320	1,125	23,517	4,108	4,700	7,762	4,846	112,294
	31.98%	27.00%	1.00%	20.94%	3.66%	4.19%	6.91%	4.32%	100.00%
2024	35,916	30,320	1,125	23,517	4,108	4,700	8,061	4,846	112,593
	31.90%	26.93%	1.00%	20.89%	3.65%	4.17%	7.16%	4.30%	100.00%

※ 1. The capacities outlook is based on year-end

※ 2. The distributed generation (non-centrally dispatched generating unit) capacity is derived by excluding the capacity with uncertain levels of contribution to peak time

□ Metropolitan Area

[unit: ㎿, %]

Year	Nuclear	Bituminous Coal	Anthra-cite	LNG	Oil	Pumped storage	Renewa-ble	RCS	Inter Change	Total
2009	0	3,340	0	10,502	1,400	400	242	838	13,500	30,222
	0.00%	11.05%	0.00%	34.75%	4.63%	1.32%	0.80%	2.77%	44.67%	100.00%
2010	0	3,340	0	10,502	1,400	400	253	1,178	14,355	31,428
	0.00%	10.63%	0.00%	33.42%	4.45%	1.27%	0.81%	3.75%	45.68%	100.00%
2011	0	3,340	0	11,652	1,400	400	429	1,700	14,801	33,722
	0.00%	9.90%	0.00%	34.55%	4.15%	1.19%	1.27%	5.04%	43.89%	100.00%
2012	0	3,340	0	12,935	1,400	400	429	1,931	15,463	35,898
	0.00%	9.30%	0.00%	36.03%	3.90%	1.11%	1.20%	5.38%	43.07%	100.00%
2013	0	3,340	0	13,685	1,400	400	429	2,292	15,957	37,503
	0.00%	8.91%	0.00%	36.49%	3.73%	1.07%	1.14%	6.11%	42.55%	100.00%
2014	0	5,080	0	14,948	1,400	400	434	2,709	16,528	41,499
	0.00%	12.24%	0.00%	36.02%	3.37%	0.96%	1.05%	6.53%	39.83%	100.00%
2015	0	5,080	0	14,498	1,400	400	434	2,765	16,449	41,026
	0.00%	12.38%	0.00%	35.34%	3.41%	0.97%	1.06%	6.74%	40.09%	100.00%
2016	0	5,080	0	14,498	1,400	400	434	2,765	16,695	41,272
	0.00%	12.31%	0.00%	35.13%	3.39%	0.97%	1.05%	6.70%	40.45%	100.00%
2017	0	5,080	0	14,498	1,400	400	1072	2,765	16,990	42,205
	0.00%	12.04%	0.00%	34.35%	3.32%	0.95%	2.54%	6.55%	40.26%	100.00%
2018	0	5,080	0	14,498	1,400	400	1072	2,765	17,442	42,657
	0.00%	11.91%	0.00%	33.99%	3.28%	0.94%	2.51%	6.48%	40.89%	100.00%
2019	0	5,080	0	14,498	1,400	400	1072	2,765	17,200	42,415
	0.00%	11.98%	0.00%	34.18%	3.30%	0.94%	2.53%	6.52%	40.55%	100.00%
2020	0	5,080	0	14,498	1,400	400	1072	2,765	18,742	43,957
	0.00%	11.56%	0.00%	32.98%	3.18%	0.91%	2.44%	6.29%	42.64%	100.00%
2021	0	5,080	0	14,498	1,400	400	1072	2,765	19,234	44,449
	0.00%	11.43%	0.00%	32.62%	3.15%	0.90%	2.41%	6.22%	43.27%	100.00%
2022	0	5,080	0	14,498	1,400	400	1072	2,765	19,414	44,629
	0.00%	11.38%	0.00%	32.49%	3.14%	0.90%	2.40%	6.20%	43.50%	100.00%
2023	0	5,080	0	14,498	1,400	400	1072	2,765	18,819	44,034
	0.00%	11.54%	0.00%	32.92%	3.18%	0.91%	2.43%	6.28%	42.74%	100.00%
2024	0	5,080	0	14,498	1,400	400	1072	2,765	18,832	44,047
	0.00%	11.53%	0.00%	32.91%	3.18%	0.91%	2.43%	6.28%	42.75%	100.00%

※ 1. The capacities outlook is based on year-end

※2. The distributed generation (non-centrally dispatched generating unit) capacity is derived by excluding the capacity with uncertain levels of contribution to peak time

□ Jeju Island

[unit: ㎿, %]

Year	Nuclear	Bituminous Coal	Anthra-cite	LNG	Oil	Pumped storage	Renewa-ble	RCS	HVDC	Total
2009	0	0	0	0	670	0	21	0	150	841
	0.00%	0.00%	0.00%	0.00%	79.67%	0.00%	2.50%	0.00%	17.84%	100.00%
2010	0	0	0	0	670	0	24	0	150	844
	0.00%	0.00%	0.00%	0.00%	79.38%	0.00%	2.84%	0.00%	17.77%	100.00%
2011	0	0	0	0	670	0	44	0	400	1,114
	0.00%	0.00%	0.00%	0.00%	60.14%	0.00%	3.95%	0.00%	35.91%	100.00%
2012	0	0	0	0	630	0	69	0	400	1,099
	0.00%	0.00%	0.00%	0.00%	57.32%	0.00%	6.28%	0.00%	36.40%	100.00%
2013	0	0	0	0	575	0	74	0	400	1,049
	0.00%	0.00%	0.00%	0.00%	54.81%	0.00%	7.05%	0.00%	38.13%	100.00%
2014	0	0	0	0	575	0	121	0	400	1,096
	0.00%	0.00%	0.00%	0.00%	52.46%	0.00%	11.04%	0.00%	36.50%	100.00%
2015	0	0	0	0	575	0	144	0	400	1,119
	0.00%	0.00%	0.00%	0.00%	51.39%	0.00%	12.87%	0.00%	35.75%	100.00%
2016	0	0	0	0	575	0	168	0	400	1,143
	0.00%	0.00%	0.00%	0.00%	50.31%	0.00%	14.70%	0.00%	35.00%	100.00%
2017	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2018	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2019	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2020	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2021	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2022	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2023	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%
2024	0	0	0	0	575	0	168	0	600	1,343
	0.00%	0.00%	0.00%	0.00%	42.81%	0.00%	12.51%	0.00%	44.68%	100.00%

※ 1. The capacities outlook is based on year-end

※ 2. The distributed generation (non-centrally dispatched generating unit) capacity is derived by excluding the capacity with uncertain levels of contribution to peak time

3. Generation Outlook by Fuel Type

[unit: GWh, %]

Year	Nuclear	Bituminous Coal	Anthracite	LNG	Oil	Pumped storage	Total
2010	144,856	193,476	100,690	14,693	2,084	5,949	461,747
	31.4%	41.9%	21.8%	3.2%	0.5%	1.3%	100%
2011	157,008	196,332	98,038	19,334	1,399	8,629	480,740
	32.7%	40.8%	20.4%	4%	0.3%	1.8%	100%
2012	169,077	193,723	105,272	16,875	1,607	11,123	497,676
	34%	38.9%	21.2%	3.4%	0.3%	2.2%	100%
2013	181,299	193,265	107,656	13,717	1,474	15,452	512,863
	35.4%	37.7%	21%	2.7%	0.3%	3%	100%
2014	192,754	197,356	107,805	9,840	1,372	17,635	526,761
	36.6%	37.5%	20.5%	1.9%	0.3%	3.3%	100%
2015	201,089	220,886	89,891	6,795	2,551	20,009	541,221
	37.2%	40.8%	16.6%	1.3%	0.5%	3.7%	100%
2016	207,890	239,900	75,436	3,699	4,014	23,205	554,144
	37.5%	43.3%	13.6%	0.7%	0.7%	4.2%	100%
2017	218,692	235,716	74,232	3,501	4,812	28,026	564,979
	38.7%	41.7%	13.1%	0.6%	0.9%	5%	100%
2018	223,917	234,438	74,742	3,405	4,843	32,407	573,752
	39%	40.9%	13%	0.6%	0.8%	5.6%	100%
2019	235,557	228,597	73,586	3,210	5,244	36,081	582,275
	40.5%	39.3%	12.6%	0.6%	0.9%	6.2%	100%
2020	259,378	217,454	62,081	3,039	6,256	40,648	588,856
	44%	36.9%	10.5%	0.5%	1.1%	6.9%	100%
2021	270,078	208,832	61,113	2,926	6,413	44,272	593,634
	45.5%	35.2%	10.3%	0.5%	1.1%	7.5%	100%
2022	282,314	196,553	62,170	2,915	7,125	47,892	598,968
	47.1%	32.8%	10.4%	0.5%	1.2%	8%	100%
2023	294,402	186,524	61,149	2,891	8,416	51,533	604,915
	48.7%	30.8%	10.1%	0.5%	1.4%	8.5%	100%
2024	295,399	188,411	59,201	2,912	8,202	54,467	608,591
	48.5%	31%	9.7%	0.5%	1.3%	8.9%	100%

4. Generation Capacity Expansion and Retirement

A. Generation Capacity Expansion by year

□ Nationwide

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW]
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
2009		72,257	72,185		66,797	8.2	Existing Capacity		
2010		73,247	75,416	70,457	69,886	4.0~4.8			
	4						Songdo CHP (Incheon Total Energy)		187.3
	5						GunSan#1		718.4
	5						Incheon Airport Energy (changed to centrally dispatched unit)		71.1
	6						Iksan industrial estate 2 CHP		3.2
	6						Small hydro power		1.4
	6						Wind power		0.6
	6						Solar power		24.5
	6						Biomass		0.4
	6						Waste		2.2
	6						Fuel cell		1.2
	10						Yeongwol C/C#1		853
	11						Pangyo CHP		146.1
	11						Daegu RCS(wood chip)		3.0
	12						Singori#1 (KHNP)		1,000
	12						Island Area Int. (Socheongdo etc)		5.5
	12						Ret-Island Area Int.		-1.6
	12						Sinjeong 3 section RCS		2.6
	12						Sinnae section RCS		5.3
	12						Small hydro power		0.3
	12						Wind power		27.9
	12						Solar power		18.8
	12						Biomass(RPS 4)		2.8
	12						By-product gas (Gwangyang by-product gas#1, Jecheol thermal power #3~4)		135.9
	12						Fuel cell		20.8
2011		77,408	78,957	73,713	72,620	5.0~6.6			
	1						Daejeon southwest CHP		48.3
	1						Gunjang National industrial CHP		55.1
	2						Paju CHP		515
	2						Posco C/C #5 (Posco power)		575

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW]
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
	6						Posco C/C #6 (Posco power)		575
	6						Hydro power(Cheongpyeong hydro add)		60
	6						Small hydro power		0.5
	6						Wind power		21.9
	6						Ocean energy (Lake Sihwa tidal power)		75
	6						Solar power		8.2
	6						By-product gas (April: Gwangyang by-product gas#2)		56.4
	6						Fuel cell		1.4
	9						Ret-Boryeong C/C#4		-450
	9						Yecheon PS#1(KOMIPO)		400
	11						Pyeongtaek Sosabul section CHP		7
	12						Singori#2(KHNP)		1,000
	12						Yecheon PS#2(KOMIPO)		400
	12						Island Area Int (Ulneungdo etc)		14.3
	12						Ret-Island Area Int		-2.3
	12						Small hydro power		25.2
	12						Wind power		97.2
	12						Solar power		15.8
	12						Biomass(RPS 4)		4.0
	12						Waste		1.3
	12						Fuel cell		36.6
2012		79,839	81,713	76,161	74,414	4.8~7.3			
	1						Ret-Nam Jeju Int. #1-4 (KOSPO)		-40
	1						Ret-Yeosu Thermal #1 (KOSEP)		-200
	3						Sinwolseong#1(KHNP)		1,000
	6						Yeosu RCS		21.3
	6						Small hydro Power		0.5
	6						Wind Power		95.8
	6						Waste(GwangjuJeonnam innovation city)		4.0
	6						Solar power		0.5
	10						Namyangju Byeollae CHP		85.5
	10						SuwonGwanggyo CHP		144.8
	10						Yangsan Sasong Section CHP		47.1
	10						Wonju CHP		27.7
	12							Incheon C/C #3 (KOMIPO)	450
	12							Oseong C/C (SK E&S)	833

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW]
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
	12						Island Area Int (Paikryeongdo etc)		18.4
	12						Ret-Island Area Int		-7.5
	12						Solar power (RPS 299.5)		54.7
	12						Biomass(RPS)		1.6
	12						Fuel cell		20
	12						By-produc gas (Pohang by-product gas#1)		59.6
							Geothermal heat power(RPS)		0.2
	12						Wind power		138.5
2013		82,750	85,945	79,784	76,207	3.7~8.6			
	1						Ret-YoungNam thermal#1,2 (KOSPO)		-400
	1						Ret-Jeju thermal GT #3 (KOMIPO)		-55
	1						Sinwolseong#2(KHNP)		1,000
	1						Gimcheon industrial section RCS		24.7
	5						Daegu technopolis general industrial section RCS		56
	5						Yangju CHP		244.5
	6						Wind power		34.2
	6						Solar power		0.6
	6						Biomass		11.9
	6						waste		1.5
	6						By-product gas (Pohang by-product gas #2-3)		119.2
	9						Singori#3(KHNP)		1,400
	9						Hwasung Hyangnam 2 sectionCHP		100.4
	10						Ret-Boryung C/C#3		-450
	11						Hangbok city CHP		515
	12							Pocheon C/C#1 (Pocheon Power)	750
	12							Bugok C/C#3 (GS EPS)	500
	12						Island Area Int (Jawoldo etc)		1.6
	12						Ret-Island Area Int		-0.7
	12						Ganddong section RCS		16
	12						Asantangjeong section RCS		52
	12						Wind power		53.7
	12						Small hydro power		0.8
	12						Solar power (RPS)		55.6
	12						Biomass(RPS 6)		81.9
	12						Waste		7.9
	12						Fuel cell(RPS)		30.5
	12						By-product gas(Jecheol thermal power #5~6)		79.5
	12							Anddong C/C (KOSPO)	400

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
2014		88,858	90,869	83,360	78,017	6.6~13.9			
	1						Ret-Ulsan Thermal#1-3(EWP)		-600
	3							Ansan C/C#1 (POSCO E&C)	750
	5							Jangheung C/C (SK E&S)	800
	6							Munsan C/C (SK E&C)	800
	6							Youngheung thermal#5(KOSEP)	870
	6						Wind power		28.8
	6						Ocean energy (Yuldolmok tidal current power)		14.9
	7						Osan C/C thermal		121.1
	8						Ret-POSCO C/C#1(POSCO Power)		-450
	9						Singori#4(KHNP)		1,400
	9							Pocheon C/C#2 (Pocheon power)	750
	10							Chuncheon C/C (POSCO E&C)	500
	11						Siheung Janghyeon Mokgam Section CHP		16.7
	12							Youngheung thermal# 6(KOSEP)	870
	12						Ret-Seoul thermal #4,5(KOMIPO)		-387.5
	12						Island Area Int (Ulneungdo etc)		13.8
	12						Ret-Island area Int		-6.0
	12						Wirye Energy		280.0
	12						Kyungnam Jinju innovation section CHP		5.3
	12						Wind power		23.4
	12						Solar power(RPS)		59.4
	12						Biomass(RPS)		2.4
	12						Waste(RPS)		9.9
	12						Fuel cell(RPS)		50
	12						Small hydro power		2.3
	12							Seoul C/C#1,2 (KOMIPO)	1,000
	12							Dongducheon C/C #1,2(Samsung C&T))	1,500

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
	12							Donghae private investment #1(STX)	500
2015		92,465	96,283	86,754	80,009	6.6~15.6			
	1						Ret-POSCO C/C#2(POSCO Power)		-450
	2							POSCO C/C#7 (POSCO Power)	600
	4							Donghae private investment#2(STX)	500
	5						Anseung new town section		45.8
	6							Dongbu Green#1,2	1,000
	8							POSCO C/C#8 (POSCO Power)	600
	9						Daegu innovation city CHP		200
	11							Yeosu1(KOSEP)	350
	12							Dangjin thermal#9 (EWP)	1,000
	12							Samcheok#1,2 (KOSPO)	2,000
	12						Youngjong EP power plant(Unbuk)		9.7
	12						Small hydro power(RPS)		4.7
	12						Wind power		23.4
	12						Ocean energy (Garolim tidal power)		153.6
	12						Solar power (RPS-347.8)		64.3
	12						Biomass(RPS)		2.4
	12						Waste(RPS)		10.3
	12						Fuel cell(RPS)		50
	12						IGCC(Taean)		300
2016		98,697	98,837	89,629	81,988	10.1~20.4			
	6							Dangjin thermal#10(EWP)	1,000
	6							Sinboryeong#1 (KOMIPO)	1,000
	6							Taean#9(WP)	1,000
	6							Sinuljin#1(KHNP)	1,400
	6						Solar power		12.9
	6						Biomass		0.3
	12						Seokmun national industrial secion		17.1
	12						Small hydro power(RPS)		4.7
	12						Wind power		23.4
	12						Biomass(RPS)		2.4
	12						Waste(RPS)		10.7
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		0.9
	12						Solar power (RPS-170.39)		30.8

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
	12							Taean#10(WP)	1,000
2017		100,626	101,311	92,281	83,913	9.0~19.9			
	6							Sinuljin#2(KHNP)	1,400
	6							Sinboryeong#2 (KOMIPO)	1,000
	6						Ocean energy (Incheon tide tidal power)		389.8
	12						Ocean energy (Ganghwa tidal power, Wando tidal current power)		263.7
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		8.5
	12						Biomass(RPS)		2.4
	12						Waste(RPS)		11.1
	12						Fuel cell(RPS)		50
	12						IGCC(Youngnam)		300
	12						Solar power(RPS-244.43)		44.4
2018		101,311	101,568	95,075	85,810	6.6~18.1			
	6						Solar power		0.1
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		147.8
	12						Solar power(RPS)		40.8
	12						Biomass(RPS)		2.4
	12						Waste(RPS)		11.5
	12						Fuel cell(RPS)		50
	12							Singori#5(KHNP)	1,400
2019		102,968	104,097	97,405	87,607	5.7~17.5			
	11						Hangbok city CHP		515
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		197
	12						Solar power(RPS)		43.7
	12						biomass(RPS)		4.0
	12						Waste(RPS)		11.9
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		2.7
	12						IGCC(Gunjang)		300
	12							Singori#6(KHNP)	1,400
2020		106,897	107,285	99,653	89,225	7.3~19.8			
	6							Sinuljin#3(KHNP)	1,400
	12						Small hydro power(RPS)		4.7

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
	12						Wind power(RPS)		270.9
	12						Solar power(RPS)		42.9
	12						Biomass(RPS)		4.0
	12						Waste(RPS)		12.4
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		2.7
2021		108,185	108,570	101,640	90,713	6.4~19.3			
	1						Ret-Honam thermal #1,2(EWP)		-500
	6							Sinuljin#4(KHNP)	1,400
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		270.9
	12						Solar power(RPS)		38.1
	12						Biomass (RPS)		4.0
	12						Waste(RPS)		12.7
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		4.5
2022		110,070	110,457	103,644	92,111	6.2~19.5			
	6							Singori#7(KHNP)	1,500
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		270.9
	12						Solar power(RPS)		40.4
	12						Biomass(RPS)		4.0
	12						Waste(RPS)		13.1
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		4.5
2023		111,957	112,294	105,614	93,598	6.0~19.6			
	6							Singori#8(KHNP)	1,500
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		216.7
	12						Solar power(RPS)		42.9
	12						Biomass(RPS)		4.0
	12						Waste(RPS)		13.4
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		5.4
2024		112,294	112,593	107,437	95,038	4.5~18.2			
	12						Small hydro power(RPS)		4.7
	12						Wind power(RPS)		173.4
	12						Solar power (RPS)		45.8
	12						Biomass(RPS)		4.0
	12						Waste(RPS)		13.7
	12						Fuel cell(RPS)		50
	12						Geothermal heat power(RPS)		7.2

※ 1. Installed Reserve Margin is based on July.

※ 2. The distributed generation (renewables, non-centrally dispatched generating unit) capacity is derived by excluding the capacity with uncertain levels of contribution to peak time.

※ 3. The expected delay rate of construction for utilities scheduled to be constructed.

- It is supposed that the expected delay rates of construction for utilities under construction and scheduled to be retired are 0%.

Year	The expected delay rate of construction for utilities scheduled to be constructed [%]			Year	The expected delay rate of construction for utilities scheduled to be constructed [%]		
	Nuclear	Coal	C/C		Nuclear	Coal	C/C
2010	-	-	-	2018	53	5	27
2011	-	-	-	2019	29	0	22
2012	-	-	-	2020	7	0	22
2013	-	-	-	2021	0	0	19
2014	-	9	52	2022	0	0	19
2015	-	9	41	2023	0	0	19
2016	50	9	28	2024	0	0	19
2017	59	13	29				

※ The rates outlook is based on summer peak.

※ As Sinboreong #1, 2 are utilities of a political project (demonstration business), the possibility of timely completion will be studied along with the progress and results of the business.

□ Metropolitan area

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
2009		30,516	30,222		26,285	14.4	Existing Capacity		
2010		31,266	31,428	28,316	28,056	10.4~11.4			
	1						ATC increment		855
	4						Songdo CHP (Incheon Total Energy)		187.3
	6						Solar power		0.8
	6						Waste		1.7
	11						Pangyo CHP		146.1
	12						Sinjeong 3 section RCS		2.6
	12						Sinnae section RCS		5.3
	12						Wind power		1.3
	12						Solar power		1.0
	12						Fuel cell		5.2
2011		33,680	33,722	29,469	29,052	14.3~15.9			
	1						ATC increment		446
	2						Paju CHP		515
	2						Posco C/C #5 (Posco power)		575
	6						Posco C/C #6 (Posco power)		575
	6						Hydro power(Cheongpyeong hydro add) (KHNP)		60
	6						Wind power		4.9
	6						Ocean energy (Lake Sihwa tidal power)		75
	6						Solar power		0.9
	11						Pyeongtaek Sosabul section CHP		7
	12						Small hydro power		8.1
	12						Solar power		0.0
	12						Waste		1.3
	12						Fuel cell		26.2
2012		34,384	35,898	30,465	29,795	12.9~15.4			
	1						ATC increment		662
	6						Solar power		0.0
	10						Namyangju Byeollae CHP		85.5
	10						SuwonGwanggyo CHP		144.8
	12							Incheon C/C #3 (KOMIPO)	450
	12							Oseong C/C (SK E&S)	833
2013	1	36,636	37,503	31,972	30,579	14.6~19.8	ATC increment		494
	5						Yangju CHP		244.5
	6						Solar power		0.1

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
	9						Hwasung Hyangnam 2 sectionCHP		100.4
	12							Pocheon C/C#1 (Pocheon Power)	750
	12						Ganddong section RCS		16
2014		40,942	41,392	33,454	31,358	22.4~30.6			
	1						ATC increment		464
	3							Ansan C/C#1 (POSCO E&C)	750
	5							Jangheung C/C (SK E&S)	800
	6							Munsan C/C (SK E&C)	800
	6							Youngheung thermal#5(KOSEP)	870
	6						Wind power		5.4
	7						Osan C/C thermal		121.1
	8						Ret-POSCO C/C#1(POSCO Power)		-450
	9							Pocheon C/C#2 (Pocheon power)	750
	11						Siheung Janghyeon Mokgam Section CHP		16.7
	12							Youngheung thermal# 6(KOSEP)	870
	12						Ret-Seoul thermal #4,5(KOMIPO)		-387.5
	12						Uirye Energy		280
	12							Seoul C/C#1,2 (KOMIPO)	1,000
	12							Dongducheon C/C #1,2(Samsung C&T))	1,500
2015		40,909	40,919	34,850	32,193	17.4~27.1			
	1						ATC increment		-79
	1						Ret-POSCO C/C#2(POSCO Power)		-450
	2							POSCO C/C#7 (POSCO Power)	600
	5						Anseung new town section		45.8
	8							POSCO C/C#8 (POSCO Power)	600
	12						Youngjon EP power plant(Unbuk)		9.7

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
2009		30,516	30,222		26,285	14.4	Existing Capacity		
2010		31,266	31,428	28,316	28,056	10.4~11.4			
	1						ATC increment		855
	4						Songdo CHP (Incheon Total Energy)		187.3
	6						Solar power		0.8
	6						Waste		1.7
	11						Pangyo CHP		146.1
	12						Sinjeong 3 section RCS		2.6
	12						Sinnae section RCS		5.3
	12						Wind power		1.3
	12						Solar power		1.0
	12						Fuel cell		5.2
2011		33,680	33,722	29,469	29,052	14.3~15.9			
	1						ATC increment		446
	2						Paju CHP		515
	2						Posco C/C #5 (Posco power)		575
	6						Posco C/C #6 (Posco power)		575
	6						Hydro power(Cheongpyeong hydro add) (KHNP)		60
	6						Wind power		4.9
	6						Ocean energy (Lake Sihwa tidal power)		75
	6						Solar power		0.9
	11						Pyeongtaek Sosabul section CHP		7
	12						Small hydro power		8.1
	12						Solar power		0.0
	12						Waste		1.3
	12						Fuel cell		26.2
2012		34,384	35,898	30,465	29,795	12.9~15.4			
	1						ATC increment		662
	6						Solar power		0.0
	10						Namyangju Byeollae CHP		85.5
	10						SuwonGwanggyo CHP		144.8
	12							Incheon C/C #3 (KOMIPO)	450
	12							Oseong C/C (SK E&S)	833
2013	1	36,636	37,503	31,972	30,579	14.6~19.8	ATC increment		494
	5						Yangju CHP		244.5
	6						Solar power		0.1

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility		Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand		▪ Under construction ▪ To be retired ▪ Island, RCS, Renewable	▪ Scheduled	
2016		41,408	41,408	36,035	33,016	14.9~25.4			
	1						ATC increment		489
2017		42,093	42,341	37,131	33,819	13.4~24.5			
	1						ATC increment		295
	6						Ocean energy (Incheon tide tidal power)		389.8
	12						Ocean energy (Ganghwa tidal power, Wando tidal current power)		248.1
2018		42,532	42,532	38,270	34,594	11.1~22.9			
	1						ATC increment		191
2019		43,119	43,119	39,225	35,329	9.9~22.0			
	1						ATC increment		587
2020		44,661	44,661	40,182	36,023	11.1~24.0			
	1						ATC increment		1,542
2021		45,153	45,153	41,034	36,661	10.0~23.2			
	1						ATC increment		492
2022		45,333	45,333	41,859	37,230	8.3~21.8			
	1						ATC increment		180
2023		44,738	44,738	42,580	37,746	5.1~18.5			
	1						ATC increment		-595
2024		44,751	44,751	43,187	38,191	3.6~17.2			
	1						ATC increment		13

※ 1. Installed Reserve Margin is based on July.

※ 2. The distributed generation (renewables, non-centrally dispatched generating unit) capacity is derived by excluding the capacity with uncertain levels of contribution to peak time.

※ 3. The expected delay rate of construction for utilities scheduled to be constructed.

- It is supposed that the expected delay rates of construction for utilities under construction and scheduled to be retired are 0%.

Year	The expected delay rate of construction for utilities scheduled to be constructed [%]			Year	The expected delay rate of construction for utilities scheduled to be constructed [%]		
	Nuclear	Coal	C/C		Nuclear	Coal	C/C
2010	-	-	-	2018	53	5	27
2011	-	-	-	2019	29	0	22
2012	-	-	-	2020	7	0	22
2013	-	-	-	2021	0	0	19
2014	-	9	52	2022	0	0	19
2015	-	9	41	2023	0	0	19
2016	50	9	28	2024	0	0	19
2017	59	13	29				

※ The rates outlook is based on summer peak.

□ Jeju Island

Year	Month	Capacity of reference generating expansion plan		Peak demand		Installed Reserve Margin [%]	Utility	Capacity [MW] Summer
		Summer	Winter	BAU demand	Target demand			
2009		832	841		578	44.0	Existing Capacity	
2010		841	844	625	625	34.6		
	6						Biomass	0.4
	12						Wind power	2.8
	12						Solar power	0.3
2011		848	1,114	637	627	33.1~35.2		
	6						Wind power	4.1
	12						Wind power	16
	12						HVDC#2	250
2012		1,092	1,099	667	650	63.7~68.0		
	1						Ret-Namjeju Int#1-4 (KOSPO)	-40
	6						Wind power	17.2
	12						Wind power	7.4
2013		1,044	1,049	708	675	47.5~54.7		
	1						Ret-Jeju thermalGT #3 (KOMIPO)	-55
	12						Wind power	4.9
2014		1,072	1,096	750	700	42.9~53.1		
	6						Wind power	23.4
	12						Wind power	23.4
2015		1,096	1,119	791	728	38.6~50.5		
	12						Wind power	23.4
2016		1,319	1,343	829	757	35.0~47.8		
	6						HVDC #3	200
	12						Wind power	23.4
2017		1,343	1,343	866	786	55.1~70.9		
2018		1,343	1,343	905	817	48.4~64.4		
2019		1,343	1,343	942	848	42.6~58.4		
2020		1,343	1,343	980	879	37.0~52.8		
2021		1,343	1,343	1,017	911	32.1~47.4		
2022		1,343	1,343	1,054	943	27.4~42.4		
2023		1,343	1,343	1,091	975	23.1~37.7		
2024		1,343	1,343	1,126	1,007	19.3~33.4		

※ 1. Installed Reserve Margin is based on July.

※ 2. The distributed generation (renewables, non-centrally dispatched generating unit) capacity is derived by excluding the capacity with uncertain levels of contribution to peak time.

※ 3. The capacity of Jeju GT#1, 2 (installed capacity 110 MW) operating as a synchronous phase modifier is adjusted to 40 MW.

B. Generating Capacity Retirement Plan

Year	LNG C/C	Steam Power			Internal Combustion		Capacity Retirement
		Bituminous Coal	Heavy Oil	LNG	Heavy Oill	Light Oil	
2010						Island(2.15) Deokjukdo, Socheongdo Woiyeondo, Hongdo	2.15 (11stations)
2011	Boryung C/C #4 (450)					Island (0.9) Daecheongdo	450.9 (3stations)
2012			Yeosu thermal #1 (200)		Namjeju int #1~4 (40)	Island(6.5) Paikryeongdo, Eocheongdo Sapsido,Gageodo	246.5 (17stations)
2013	Boryung C/C #3 (450)		Youngnam thermal #1,2 (400)			Island(0.65) Jawoldo Jeju thermal G/T#3(55)	905.65 (6stations)
2014	POSCO C/C #1 (450)		Ulsan thermal #1~3 (600)	Seoul thermal #4,5 (388)		Island (3.8) Seungbongdo, Wido Ulneungdo	1,441.8 (14stations)
2015	POSCO C/C #2 (450)						450 (1station)
2021		Honam thermal #1,2 (500)					500 (2stations)
Total (‘10~’24)	**1,800 (4stations)**	**500 (2stations)**	**1,200 (6stations)**	**388 (2stations)**	**40 (4stations)**	**69 (36stations)**	**3,997 (54stations)**

5. Renewable and RCS Capacity Expansion Plan

□ Outlook on Renewable Capacity Construction

[unit: MW]

Year	Hydro	Wind	Ocean Energy	Solar	Biomass	Wastes	By-product gas	Fuel cell	Geothermal heat	IGCC /CCT	Total
2009	1,614.5	345.9		414.7	86.2	36.8	230.3	22.5			2,750.9
2010	Seoribo 1.5 Buhyang dam 0.6 Gunwi dam 0.5 Cheongcheon 0.49 Tapjeong 0.32 Wontong 0.2 Juam 0.05	Youngyang 76.5 Taebaek 20 Seongsan 8 Bangameori 3 Youngwoljeopsan 2.25 Nue island 2.25 STX 2 Gamnyung localization 1.5		intention 240.8	Daegu woodchip 3 Seohwa construction 1.06 RPS 4	Hwasung city 4.4 Geolim 1.2	Jecheol thermal power #3,4 200 Gwangyang by-product gas #1 142	Ulsan Ujung 10 Ilsan Ⅱ 5.2 TCS1 5.6 KOSPO 1.2			737.8
2011	Chungpyung#4 60 Youngheung ocean 5 Gangwon Sangnam 0.8 Hoengseong dam 0.3 Seongdeok dam 0.23 Ipobo 3 yeojubo 4.95 Gangcheonbo 4.995 Hamanbo 5 Hapcheonbo 5 Dalseongbo 2.841 Gangjeongbo 3 Chilgokbo 3 Gumibo 3 Nakdanbo 3 Sangjubo 3 Buyeobo 2.64 Geumgangbo 3 Geumnambo 2.31 Juksanbo 1.22 Seungcheonbo 0.8	Imgye 50 Jeju 45 Muju 39.6 Daseongsan 34 Danyang 30 Jinan, Jangsu 30 Pyungchang 26 Gangneung 26 Daegiri 24 Hanlim 20 Youngheung localization 20 WP new 20 Haenam 20 Johyangsan 20 Uiryung 19.5 South gulf sea surface 15 Youngdeok Samgye 15 Jeju Nansan 10.5 Busan 10 KOSPO sea surface 6 Gyungpo 3	Sihwa lake tidal 254	intention 133.6	wood chip 6 RPS 4	Metropolitan area waste 3.2	Gwangyang by-product gas #2 142	Bokhap thermal 4.8 Bundang10 Songpa9 Yangju7.2 TCS1 5.6 KDHC1.4			1,181.5
2012	Angye 0.99	Daehwa 90 Gamcheon 85 Odae 66 Youngam 62 Milyang 50.6 Taepyung Hambaek 40 Goheung 40 Bonghwa 40 Hyunbuk 39.6 Gohan 39.8 Sangdo 30 Sammu sea surface 30 Wanju 30 Namwon 30 Muju 2nd 30 Imsil 30 Haenam 26 Uljin Giseong 25.5 Yanggu 20 Jeongseon 20 Sangmyung 20 Gangwon northwest 20 Pampas 20 Jeongeup 20 Sunchang 20 Changjuk 18 Asan filteratin plant 3 Onsan filteration plant 3 Gampo dam 3		intention 7.7 RPS 299.5	RPS 4	Gangwon Wonju 10	Pohang by-product gas #1 150	Seosan20	RPS 0.2		1,443.9

Year	Hydro	Wind	Ocean Energy	Solar	Biomass	Wastes	By-product gas	Fuel cell	Geothermal heat	IGCC /CCT	Total
2013	Seomjingang dam 1.7	Milyang 2nd 60 Ulsan Dongdaesan 40 Pohang Seongbeongryung 36 Mokdo sea surface 35 Pohang Cheonryungsan 30 Samcheok 28 Pohang Daebomyun 20 Pohang Janggimyun 20 Jeonnam wind power 20 Donghae Mangunsan 20 Jeju EWP 20 Kyungju Cheonghak 14 Youngcheon Bohyunsan 14		intention 3.4 RPS 209.68	Bugok 200 Donghae 30 RPS 6	Gwangju Jeonnam 20 Sejong RDF 3.8	Jecheol thermal power #5,6 200 Pohang by-product gas #2,3 300	RPS 30.5			1,462.1
2014	Youngju dam 5 Bohyunsan dam 0.17	Woljeong sea surface 95 Hankyung sea surface 95 Kyungin Ara waterway 22	Yuldolmok tidal current power 50.5	RPS 330.82	RPS 6	RPS 24.84		RPS 50			679.4
2015	RPS 10.38	Udo sea surface 95	Garolim tidal power 520	intention 10 RPS 347.8	RPS 6	RPS 25.89		RPS 50		Taean CCT 300	1,365.1
2016	RPS 10.38	Daejeong sea surface 95		intention 73 RPS 170.39	G&G 0.82 RPS 6	RPS 26.93		RPS 50	RPS 1		433.5
2017	RPS 10.38	RPS 34.4	Incheon Tide tidal power 1,320 Ganghwa tidal power 840 Wando tidal current power 53	intention 2.7 RPS 244.43	RPS 6	RPS 27.98		RPS 50		Youngnam IGCC 300	2,888.9
2018	RPS 10.38	RPS 600		intention 0.57 RPS 227.2	RPS 6	RPS 29.02		RPS 50			923.2
2019	RPS 10.38	RPS 800		RPS 242.92	RPS 10	RPS 30.07		RPS 50	RPS 3	Gunjang IGCC 300	1,446.4
2020	RPS 10.38	RPS 1,100		RPS 238.51	RPS 10	RPS 31.11		RPS 50	RPS 3		1,443
2021	RPS 10.38	RPS 1,100		RPS 211.78	RPS 10	RPS 31.98		RPS 50	RPS 5		1,419.1
2022	RPS 10.38	RPS 1,100		RPS 224.64	RPS 10	RPS 32.85		RPS 50	RPS 5		1,432.9
2023	RPS 10.38	RPS 880		RPS 238.92	RPS 10	RPS 33.71		RPS 50	RPS 6		1,229
2024	RPS 10.38	RPS 704		RPS 254.75	RPS 10	RPS 34.58		RPS 50	RPS 8		1,071.7
New	232.5	8,628.1	3,037.5	3,813.1	348.9	371.6	1,134	660.5	31.2	900	19,157.4
Total	1,847	8,974	3,037.5	4,227.8	435.1	408.4	1,364.3	683	31.2	900	21,908.3

□ RCS Facilities Expansion Plan

Classification	Completion	Plant Name	Capacity (MW)	Company	Location	Remarks
General	10.04	Songdo CHP	187.3	Inchon Total Energy	Yeonsu	In the 4th plan(205㎿)
	10.06	Iksan industrial estate 2 CHP	7.3	Sanggong Energy	Iksan	In the 4th plan (‘09.12, 3㎿)
	10.11	Pangyo CHP	146.0	KDHC	Seongnam	In the 4th plan (‘09.11)
	10.11	Daegu RCS(woodchip)	3.0	KDHC	Daegu	Duplication corrected In the 4th plan (465㎿)
	10.12	Sinjeong 3 section RCS	6.0	SH Corporation	Seoul	In the 4th plan(‘09.12, 구역)
	10.12	Sinnae section RCS	12.0	SH Corporation	Seoul	
	11.01	Gunjang national industrial estate CHP	125.0	Gunjang CHP Generation	Gunsan	In the 4th plan (120㎿)
	11.01	Daejeon southwest CHP	48.3	LH	Youseong	In the 4th plan (47.3㎿)
	11.02	Paju CHP	515.0	KDHC	Paju	In the 4th plan (‘09.11)
	11.11	Pyeongtaek Sosabul section CHP	16.0	Pyeongtaek Clean Energy	Pyeongtaek	In the 4th plan (42.3㎿, 구역)
	12.06	Yeosu RCS	48.4	Hyundai Energy	Yeosu	In the 4th plan (‘11.12, 48㎿)
	12.10	SuwonGwangyo CHP	144.8	KDHC	Suwon	In the 4th plan (141㎿)
	12.10	Wonju CHP	63.0	Chambit Wonju	Wonju	In the 4th plan (CES)
	12.10	Namyangju Byeollae CHP	194.1	Byeollae Energy	Namyang	In the 4th plan(‘10.12,107.1㎿,CES)
	12.10	Yangsan Sasong section CHP	107.0	Kyungnam Energy, KDHC	Yangsan	In the 4th plan(‘11.10,98㎿,CES)
	13.01	Gimcheon industrial section RCS	56.0	Kolon,SKE&S	Gimcheon	
	13.05	Daegu technopolis general industrial section RCS	127.1	STX Energy	Daegu	
	13.05	Yangju CHP	555.1	Daeryun Generation	Yangju	In the 4th plan(‘12.12,139.7㎿,CES)
	13.09	Hwasung Hyangnam 2 section CHP	228.0	Samchully(Huces)	Hwaseong	In the 4th plan(‘11.12,60.6㎿,CES)
	13.11	Hangbok city CHP	515.0	KDHC,KOMIPO, KOSPO	Yeongi	
	13.12	Gangdong CHP	36.3	Daehan City Gas	Seoul	In the 4th plan(‘10.12,33.4㎿,CES)
	13.12	Asantangjeong section RCS	118.0	LH	Asan	
	14.07	Osan C/C thermal	121.1	Daesung	Osan	In the 4th plan (‘13.12, 76㎿)
	14.11	Siheung CHP	38.0	GS Power	Siheung	In the 4th plan (72.1㎿, CES)
	14.12	Uirye Energy	280.0	SKE&S, KDHC	Seoul	In the 4th plan (‘12.10, 228㎿)
	14.12	Kyungnam Jinju innovation city CHP	12.0	Moorim Powertech	Jinju	In the 4th plan (‘13.12, 42.6㎿)
	15.05	Anseong new town section	45.8	Pyeongtaek Clean Energy	Anseong	
	15.09	Daegu innovation city CHP	200.0	Daegu City Gas,KOSPO	Daegu	In the 4th plan (‘11.10, 227㎿)
	15.12	Youngjong EP power plant	22.1	YoungjongEP	Junggu	In the 4th plan (‘12.08, 77㎿, CES)
	16.12	Seokmun CHP	38.9	SKE&S,EWP,Seo hae City Gas	Dangjin	
	19.11	Hangbok city CHP	515.0	KDHC,KOMIPO, KOSPO	Yeongi	
	Total		**4,531.6**			

6. Electricity Supply and Demand in the Island Areas

□ Generator construction and retirement (19 islands)

○ New construction (total of 48 units 52,750kW)

○ Existing facilities retirement (total of 47 units 17,900kW)

[unit: kW]

Classification	2009	2010	2011	2012	2013	2014	Total	Remarks
Paikryungdo	9,000			9,000 (4,500)			9,000 (4,500)	3,000×3 1,500×3
Daecheongdo	1,850		2,600 (900)				2,600 (900)	1,300×2 450×2
Yeonpyeongdo	3,350		5,700 (1,350)				5,700 (1,350)	1,900×3 450×3
Duckjukdo	2,900					1,000 (900)	1,000 (900)	500×2 300×3
Jawoldo	950	1,000 (300)			1,600 (650)		2,600 (950)	500×2, 800×2 150×3, 500×1
Seungbongdo	1,950					1,000 (450)	1,000 (450)	500×2 150×3
Sapsido	900			1,000 (300)			1,000 (300)	500×2 150×2
Wido	2,850					500 (1,350)	500 (1,350)	500×1 450×3
Jodo	2,000			500			500	500×1
Ulneungdo	13,200		6,000			9,000 (2,000)	15,000 (2,000)	3,000×5 1,000×2
Chujado	4,400			3,900 (900)			3,900 (900)	1,300×3 300×3
Gaeyado	1,500					250 (500)	250 (500)	250×1 250×2
Geomundo	3,500			2,000 (1,000)			2,000 (1,000)	1,000×2 500×2
Socheongdo	700	2,400 (450)					2,400 (450)	800×3 150×3
Eocheongdo	900			1,000 (300)			1,000 (300)	500×2 150×2
Oeyeondo	600	450 (300)					450 (300)	150×3 100×3
Hongdo	1,250	1,600 (500)					1,600 (500)	800×2 250×2
Gageodo	1,050			1,000 (500)			1,000 (500)	500×2 250×2
Chodo	750					450 (750)	450 (750)	150×3 250×3
Total		5,450 (1,550)	14,300 (2,250)	18,400 (7,500)	1,600 (650)	12,200 (5,950)	51,950 (17,900)	

※ 1. Values in parenthesis denote the retirement capacity.

□ Electricity Supply and Demand Outlook

○ The installed reserve margin for 2010 ~ 2014 is maintained at 4.36~ 377.55%

[unit: kW, %]

Classification		2010	2011	2012	2013	2014
Paikryungdo	Capacity	9,000	9,000	13,500	13,500	13,500
	Capacity reserve margin	13.18	4.36	50.92	45.57	40.45
Daecheongdo	Capacity	1,850	3,550	3,550	3,550	3,550
	Capacity reserve margin	16.57	100.24	85.42	72.27	60.39
Yeonpyeongdo	Capacity	3,350	7,700	7,700	7,700	7,700
	Capacity reserve margin	17.66	97.16	78.30	61.45	46.36
Duckjukdo	Capacity	2,900	2,900	2,900	2,900	3,000
	Capacity reserve margin	51.06	47.21	42.90	38.01	36.96
Jawoldo	Capacity	1,650	1,650	1,650	2,600	2,600
	Capacity reserve margin	93.01	72.29	55.35	120.70	99.05
Seungbongdo	Capacity	1,950	1,950	1,950	1,950	2,500
	Capacity reserve margin	58.86	51.38	44.15	38.68	71.55
Sapsido	Capacity	900	900	1,600	1,600	1,600
	Capacity reserve margin	53.78	44.63	142.36	128.93	116.67
Wido	Capacity	2,850	2,850	2,850	2,850	2,000
	Capacity reserve margin	192.14	190.19	190.73	193.67	109.87
Jodo	Capacity	2,000	2,000	2,500	2,500	2,500
	Capacity reserve margin	39.40	33.86	61.32	58.17	55.09
Ulneungdo	Capacity	13,200	19,200	19,200	19,200	26,200
	Capacity reserve margin	13.16	37.49	20.23	15.73	51.86
Chujado	Capacity	4,400	4,400	7,400	7,400	7,400
	Capacity reserve margin	32.62	9.80	66.01	58.50	51.32
Gaeyado	Capacity	1,500	1,500	1,500	1,500	1,250
	Capacity reserve margin	161.61	163.93	171.94	186.91	159.53
Geomundo	Capacity	3,500	3,500	4,500	4,500	4,500
	Capacity reserve margin	83.90	26.31	58.56	54.91	51.52
Huksando	Capacity	4,000	4,000	4,000	4,000	4,000
	Capacity reserve margin	72.14	71.44	67.00	66.92	67.74
Gageodo	Capacity	1,050	1,050	1,550	1,550	1,550
	Capacity reserve margin	75.20	41.13	86.81	70.69	55.81
Janggodo	Capacity	440	440	440	440	440
	Capacity reserve margin	97.82	78.70	65.91	53.84	42.29
Socheongdo	Capacity	2,650	2,650	2,650	2,650	2,650
	Capacity reserve margin	115.93	102.19	89.24	77.0	65.41
Eocheongdo	Capacity	900	900	1,600	1,600	1,600
	Capacity reserve margin	46.71	29.42	102.81	78.83	57.88
Oeyeondo	Capacity	750	750	750	750	750
	Capacity reserve margin	163.30	142.27	122.75	104.54	87.52
Hongdo	Capacity	2,350	2,350	2,350	2,350	2,350
	Capacity reserve margin	152	128.03	111.19	104.51	98.37
Nakwoldo	Capacity	750	750	750	750	750
	Capacity reserve margin	377.55	351.80	355.47	360.29	366.49
Chodo	Capacity	750	750	750	750	450
	Capacity reserve margin	219.73	195.20	190.16	185.38	68.50
Yeojado*	Capacity	450	450	450	450	450
	Capacity reserve margin	310.74	309.81	309.98	311.21	313.48
Sisando*	Capacity	750	750	750	750	750
	Capacity reserve margin	330.02	310.79	299.86	289.73	280.24

※ The capacity reserve margins of Nakwoldo, Yeojado and Sisando each have 3 generating units and utilities constructed early in the 1990s and are now high. However, their capacities are maintained at their present levels as the life of these utilities will come to an end soon (2015).

7. Major Transmission Facilities Expansion Plan

A. Transformation Facilities

Class-ification	Substation Name	Region	Year of Completion	Necessity
765kV	Singori	Busan Gijang	2010	○ Transmission of power from future Singori nuclear units
	Bukgyeongnam	Gyeongnam Changnyeong	2012	○ Transmission of power from future Singori nuclear units ○ Power supply to Goryeong and the southern Daegu,
	Sinuljin	Gyeongbuk Uljin	2014	○ Transmission of power from future Uljin nuclear units
	Gangwon Switching station	Gangwon Pyeongchang	2016	○ Efficiency improvement of Sinuljin-Singapyeong transmission line operations
	Bukgyonggi	Gyonggi north	2019	○ Transmission of power from Yeongdong area
345kV	Seoanseong	Kyonggi Anseong	2010	○ Power supply to Anseong, Songtan area
	Singimpo	Kyonggi Gimpo	2011	○ Power supply to Gimpo area
	Sinpocheon	Kyonggi Pocheon	2011	○ Power supply to northern capital area
	Sinchungju	Chungbuk Chungju	2011	○ Power supply to Uemseong, Jeungpyeong, Pungdong area
	Sinseongnam#2	Kyonggi Seongnam	2012	○ Power supply to Seongnam, Yongin area
	Saemangeum	Jeonbuk Gunsan	2012	○ Power supply to Gunsan area
	Sinnoksan	Busan Gangseo	2012	○ Power supply to southern Busan
	Sinuijungbu	Kyonggi Uijungbu	2013	○ Movement of Uijungbu substation
	Dongulsan	Ulsan Bukgu	2013	○ Power supply to Ulsan area
	Dongbusan	Busan Namgu	2013	○ Power supply to eastern Busan
	Changwon	Gyoengnam Changwon	2013	○ Power supply to Masan, Changwon area
	Dongseoul#2	Kyonggi Hanam	2015	○ Power supply to south-eastern Seoul
	Seoseoul#2	Kyonggi Gunpo	2015	○ Power supply to south-western Kyonggi
	Sejong	Chungnam Yeongi	2015	○ Power supply to Sejong city
	Sinbupyong	Kyonggi Bucheon	2016	○ Power supply to Kyonggi Bucheon, Seoul Gangseo area
	Seopyeongtaek	Kyonggi Pyeongtaek	2018	○ Power supply to industrial estate of southern Kyonggi
FACTS	TCSC	South-eastern capital area	2012	○ Transmission capacity increment to capital area
	BTB	Western capital area	2014	○ Fault current reduction

B. Transmission Facilities

Classi-fication	Section	Length (c-km)	Year of Completion	Necessity
765kV	Sinanseong-Singapyeong	79	2010	○ Interconnection between the capital area and rear network (southern area - eastern area)
	Singgori-Bukgyeongnam	180	2012	○ Singori units interconnection
	Gangwon-Bukkyonggi	260	2019	○ Transmission of power from Yeongdong area
	Gangwon- SinUljin	260	2019	○ Transmission of power from Yeongdong area
345kV	Seoanseong branch	11	2010	○ Power supply to Anseong, Songtan area
	Singapyeong-Sinpocheon	130	2011	○ Reinforce the northern capital area network
	Sinpocheon-Sindeokeun	104	2011	○ Reinforce the northern capital area network
	Sinchungju branch	87	2011	○ Reinforce the Chungbuk Province network
	Gunsan - Saemangeum	56	2012	○ Reinforce the Gunsan area network
	Bukgyeongnam 1st branch	68	2012	○ Singori #1, 2 nuclear plant interconnection
	Bukgyeongnam 2nd branch	120	2012	○ Singori #3, 4 nuclear plant interconnection
	Sinkimhae-Sinnoksan	40	2012	○ Reinforce the Busan Noksan industrial area network
	Seonsan branch	86	2013	○ Reinforce the Gumi area network
	Dongulsan branch	48	2013	○ Power supply to Ulsan area
	Sinulsan-Sinonsan	16	2013	○ Reinforce the Ulsan area network
	Sinyangsan-Dongbusan	20	2013	○ Power supply to eastern Busan area
	Sindeokeun - POSCO	108	2015	○ Reinforce the Incheon area network
	Sejong branch	40	2015	○ Power supply to Sejong city
	Sinbupyong#2-Youngseo	32	2016	○ Reinforce the western capital area network
	Gajeong-Sinbupyong#2	23	2016	○ Reinforce the western capital area network
	Bukkyonggi-Sinuijungbu	50	2019	○ Interconnection between the 765kV network and rear network
	Bukkyonggi-Sinpocheon	10	2019	○ Interconnection between the 765kV network and rear network
D.C transmission	#2HVDC	100	2011	○ Power supply to Jeju
	Chungnam-southern Kyonnggi	7	2016	○ Transmission capacity increment to capital area
	#3HVDC	100	2016	○ Power supply to Jeju
	Sea surface wind power HVDC	70	2018	○ Interconnection between the sea surface wind power and network

※ The construction plan may be changed based on the results of KEPCO's system assessment

8. Demand Side Management

A. Demand Side Management Targets by Year (Cumulative Total)

[unit: MW]

Year	Load Control								Efficiency Improvement							Total
	Emergency Resource			Load Control Equipment				Sub total	Light-ing	Inverter	Mot-or	Transfo rmer Pump	New	Minimum Engergy Performanc e Standard/ Standby Power	Subtotal	
	Desig nated time	Week	The day befor e	Accumul ated Air Conditio ning	Gas Air Conditio ning	Remote Air Conditio ner	Peak Load Control									
2009 (actual)	1,649	1,571	364	540	1,557	101	125	5,907	866	320	24	11	0	541	1,762	7,669
2010	1,768	1,061	707	38	93	22	32	3,721	21	58	2	10	5	291	386	4,107
2011	1,816	1,089	726	75	186	44	64	4,000	48	128	4	21	10	513	724	4,724 (616)
2012	1,861	1,116	744	113	279	66	96	4,275	83	210	7	35	16	741	1,091	5,366 (1,259)
2013	1,905	1,143	762	150	371	88	128	4,547	126	305	12	50	23	976	1,493	6,040 (1,932)
2014	1,560	1,560	780	188	464	108	160	4,820	181	415	20	68	31	1,221	1,936	6,756 (2,648)
2015	1,200	1,600	1,200	226	557	128	192	5,103	250	540	31	88	40	1,308	2,257	7,360 (3,253)
2016	820	2,050	1,230	263	650	148	224	5,385	337	678	47	111	51	1,395	2,618	8,003 (3,896)
2017	629	2,308	1,259	301	743	168	256	5,664	445	829	69	136	63	1,484	3,026	8,690 (4,582)
2018	429	2,575	1,287	338	836	188	288	5,941	578	990	100	165	76	1,570	3,479	9,420 (5,312)
2019	438	2,628	1,314	376	929	208	320	6,213	740	1,157	142	196	92	1,657	3,984	10,197 (6,090)
2020	0	3,123	1,338	414	1,022	228	352	6,477	934	1,327	197	231	109	1,744	4,542	11,019 (6,912)
2021	0	3,175	1,361	451	1,115	250	384	6,736	1,165	1,495	263	268	129	1,829	5,149	11,885 (7,778)
2022	0	3,224	1,382	489	1,207	270	416	6,988	1,434	1,657	338	308	152	1,914	5,803	12,791 (8,684)
2023	0	3,276	1,404	526	1,300	290	448	7,244	1,740	1,811	418	349	178	1,995	6,490	13,734 (9,627)
2024	0	3,326	1,426	564	1,393	310	480	7,499	2,080	1,952	496	392	206	2,076	7,203	14,702 (10,595)

※ 1. The values for 2009 are actual values; ditto for designated time and week. The values for other programs are based on the total amount of supply.

※ 2. Figures in parenthesis denote the net increments compared to 2010.

※ 3. Annual targets after 2010

◦ Designated time, week, the day before: targets for the year

◦ Other programs: 2009 actual + net increment total for the year

B. Electricity Sales Reduction by Year

[unit: GWh]

Year	Electricity Sales Reduction													
	Lighting		Inverter		Motor		Transformer /Pump		New		Minimum Energy Performance Standard /Standby Power		Total	
	Annual	Cumulative total	Annual	Cumulative total	Annual	Cumulative total	Annual	Cumulative total	Annual	Cumulative total	Annual	Cumulative total	Annual	Cumulative total
2009	92	3,191	111	1,549	4	8	5	19	-	-	1,762	1,839	1,974	6,606
2010	73	73	175	175	6	6	41	41	4	4	989	989	1,289	1,289
2011	94	167	209	384	9	15	48	89	5	9	697	1,686	1,061	2,349
2012	119	286	246	630	13	28	56	145	5	14	670	2,356	1,110	3,459
2013	151	437	288	918	20	48	64	209	6	20	660	3,016	1,188	4,647
2014	191	628	331	1,249	29	76	74	282	7	27	687	3,704	1,319	5,966
2015	240	868	375	1,623	42	118	84	367	8	35	302	4,006	1,051	7,017
2016	300	1,168	416	2,040	61	179	95	462	9	44	308	4,314	1,190	8,207
2017	373	1,542	454	2,493	86	266	107	569	10	55	312	4,626	1,343	9,550
2018	460	2,002	483	2,976	120	386	119	688	12	67	287	4,912	1,481	11,031
2019	561	2,563	503	3,479	161	547	132	820	14	80	288	5,201	1,660	12,690
2020	675	3,238	511	3,990	208	755	144	964	15	96	290	5,491	1,843	14,533
2021	800	4,038	506	4,495	254	1,009	155	1,119	17	113	287	5,777	2,018	16,552
2022	931	4,969	489	4,984	290	1,299	165	1,285	20	133	286	6,064	2,182	18,733
2023	1,060	6,029	461	5,446	307	1,606	174	1,459	22	155	260	6,323	2,283	21,017
2024	1,179	7,207	426	5,871	300	1,905	180	1,639	25	180	260	6,584	2,370	23,387

C. Investment Cost of DSM

[unit: KRW 100 million]

Year	Load Control							Efficiency Improvement						Total
	Designated time	Week	The day before	Accumulated Air Conditioning	Remote Air Conditioner	Peak Load Control	Subtotal	Lighting	Inverter	Motor	Transformer Pump	New	Subtotal	
2010	225	248	230	71	5	10	789	195	93	4	44	9	346	1,135
2011	231	255	236	70	27	7	826	249	111	6	51	11	428	1,254
2012	237	261	241	100	27	7	873	317	132	9	59	12	528	1,401
2013	243	267	247	100	27	7	891	402	153	13	68	14	650	1,541
2014	159	337	252	100	27	7	882	508	177	19	78	16	797	1,679
2015	102	288	383	100	27	7	907	639	200	28	89	18	974	1,881
2016	56	295	393	100	27	7	878	799	222	40	101	21	1,184	2,062
2017	43	332	402	150	27	7	961	993	242	57	114	24	1,430	2,391
2018	29	371	411	150	27	7	995	1,224	258	79	127	27	1,715	2,710
2019	30	378	419	150	27	7	1,011	1,492	268	106	140	31	2,038	3,049
2020	-	337	427	150	27	7	948	1,796	272	137	153	35	2,394	3,342
2021	-	343	434	150	27	7	961	2,128	270	167	165	40	2,770	3,731
2022	-	348	440	150	27	7	972	2,476	261	191	176	45	3,149	4,121
2023	-	354	447	150	27	7	985	2,820	246	202	185	51	3,504	4,489
2024	-	359	454	150	27	7	997	3,135	227	198	192	57	3,809	4,806
Total	1,355	4,773	5,416	1,841	383	108	13,876	19,172	3,133	1,256	1,743	413	25,717	39,593

※ Investment costs denote the subsidies for the year by program.