Shandong, China

Electric Sector Simulation Assumption Book

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SHANDONG, CHINA
ELECTRIC SECTOR SIMULATION ASSUMPTIONS BOOK

CHINA ENERGY TECHNOLOGY PROGRAM

MASSACHUSETTS INSTITUTE OF TECHNOLOGY
Laboratory for Energy and the Environment
Analysis Group for Regional Electricity Alternatives

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August 2002

SHANDONG, CHINA – ELECTRIC SECTOR SIMULATION ASSUMPTIONS BOOK

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Chapter 1: Overview of Electric Sector Simulation Task and Shandong Scenarios

Introduction

The Electric Sector Simulation Task of the China Energy Technology Program (CETP) employs the scenario-based multi-attribute tradeoff analysis approach, developed by AGREA, to explore the comparative performance of multi-option strategies under uncertainty. Through the use of a simulation modeling approach that captures the changes in year-to-year utilization of power plants as electricity demand and the power system evolves, cost-effective multi-pollutant emissions reduction strategies associated with electric sector modernization can be identified.

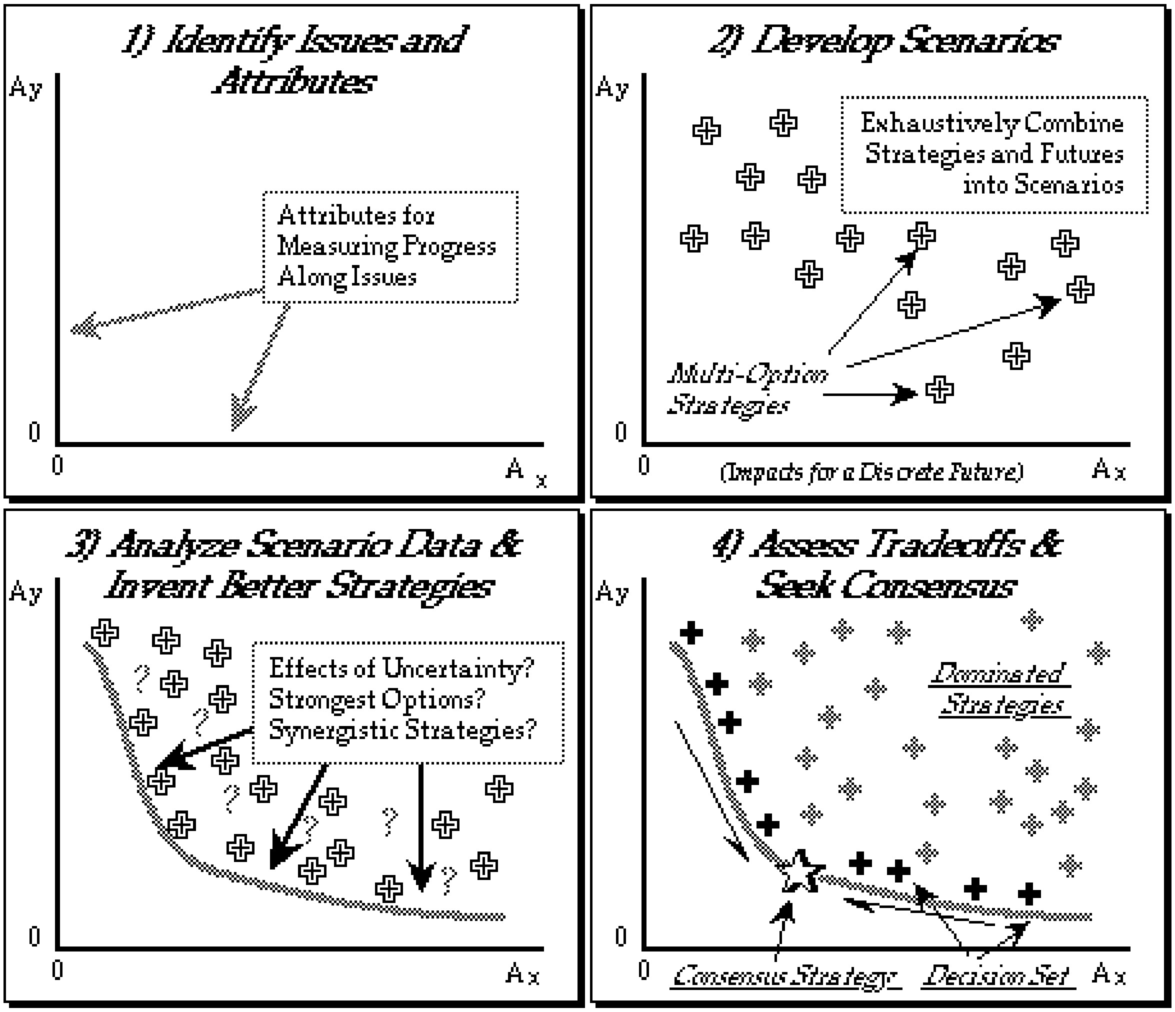
This chapter provides an overview to the approach and how it was applied to Shandong Province within the CETP. Later in the chapter we give a quick overview of Shandong Province itself. The remainder of this report explains the derivation of the modeling assumptions used in the analysis of scenarios outlined in this chapter. Computational results and their implications from the Electric Sector Simulation task are contained in Chapter Six of Integrated Assessment of Sustainable Energy Systems in China: The China Energy Technology Program: A Framework for Decision Making in the Electric Sector of Shandong Province, published by Kluwer Academic Press and edited by B. Eliasson and Y. Lee

Scenario-Based Multi-Attribute Tradeoff Analysis

The Scenario-Based Multi-Attribute Tradeoff Analysis approach – often referred to simply as tradeoff analysis – is described in more detail in Connors (1996) and Andrews (1990). A broader treatment of its use in joint fact-finding or "open planning" can be found in Andrews (2002). This approach to "infrastructure management" was developed during the 1980s at the MIT Energy Laboratory, and refined in the late 1980s and early 1990s by Connors and Andrews with the New England power sector as its principle focus, and has been applied to numerous other regions since then.

The principle purpose of the tradeoff analysis approach is to provide decisionmakers for a given region information of sufficient breadth and time horizon for them to see what portfolios of options they should encourage over the long term. Figure 1.1 illustrates this process. In the initial phase discussions among stakeholder group members and the analysis team help to identify the key areas of concern and some of the technology and policy option under consideration and contemplation. Attributes measuring strategy performance relative to the principle issues are devised, and options and uncertainties that encompass the stakeholder group's collective interests are developed. These are Steps One and Two illustrated in Figure 1.1.

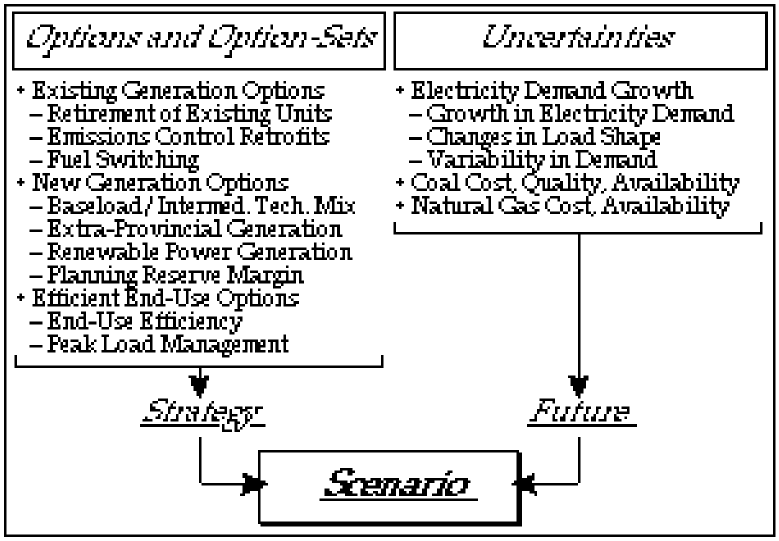
FIGURE 1.1: Four Principle Steps in the Tradeoff Analysis Approach



The scenarios are then analyzed, and through a series of iterations with stakeholders refined until such a point that a consensus strategy, or at least the "robust" elements of a strategy can be agreed upon and put into a nearer-term "tactical" plans. The tradeoff approach has several unique features that should be noted. First, it is designed to be responsive to the local decisionmakers' interests and needs. As such it is "inclusive" with many attributes and scenario options and uncertainties.

Figure 1.2 shows the elements of a scenario. Reading from the bottom up, a *scenario* is comprised of a multi-option *strategy* under a given set of circumstances (uncertainties) referred to as a *future.* Each future is made up of a set of uncertainties that have been identified through discussions with the stakeholder audience. Similarly, each multi-option strategy is made up of individual options, some technological, and some policy-oriented, that may or may not interact with one-another. Figure 1.2 also shows the "option sets" for which individual options for the Shandong ESS scenario set were developed.

FIGURE 1.2: Building Scenarios – Options and Strategies, Uncertainties and Futures

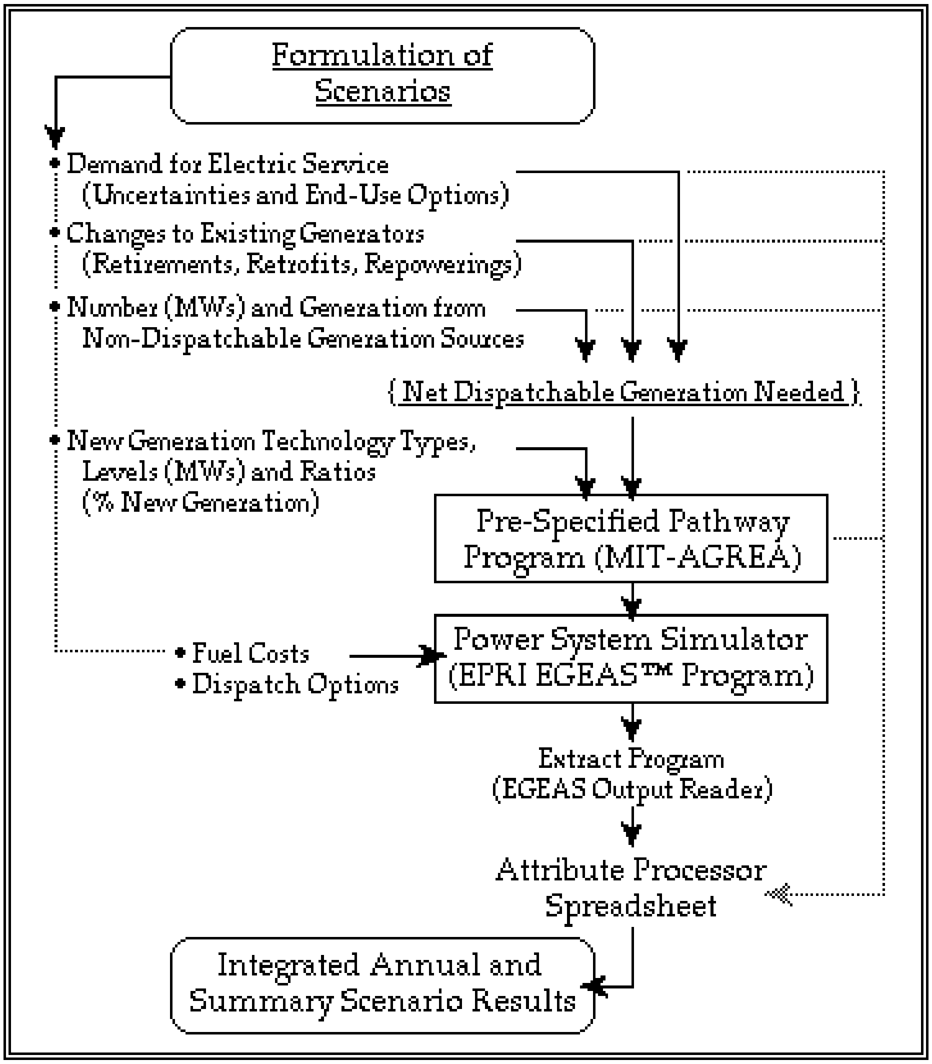


Previous research projects have guided us in the crafting of such scenario sets. Of critical importance are the inclusion of option sets that address the performance of existing infrastructure components, such as older power plants. Also important are electricity demand options, and how they influence the need for, and utilization of, new (modern, cleaner, more-efficient) generation.

In order to reasonably address this "inclusiveness" which leads to dozens of performance criteria (attributes) and thousands of scenarios, simulation rather than optimization models are generally preferred. The principle reason for this is that optimization models require clear, usually limited in number, goal states ("objective functions"), and generally have trouble converging on a solution when both the objective criteria and the number of alternatives to choose from are more than just a few. AGREA's experience has also identified some additional "benefits" of using simulation versus optimization models. In addition to quicker run times, allowing researchers to examine a greater number of alternatives, the ability to show inferior or "sub-optimal" scenarios is very instructive to stakeholder groups. Although the principle goal of the approach is to identify robust portfolios of options (strategies) across the range of uncertainties (futures) of principle interest (and often sub-optimal for several futures), being able to show what options, or combinations of options are almost never cheap and / or clean is an invaluable pedagogical tool, one which optimization models are not designed to fulfill.

Figure 1.3 provides a schematic of the suite of tasks and models the CETP ESS research team at MIT and ETH-Zurich used to analyze the Shandong ESS scenarios. The principle "engine" of the ESS scenario analysis was the EPRI EGEAS™ expansion planning suite of programs, developed in part at MIT under EPRI sponsorship in the early 1980s, and more recently updated and maintained by Stone and Webster, now part of the Shaw Group. (EPRI, 1982; Stone and Webster Management Consultants, 1991) Version 6.12 of EGEAS was used to analyze these scenarios.

FIGURE 1.3: Simplified Schematic – Analyzing a Single Scenario



Since EGEAS's capacity expansion algorithms do not adequately reflect the impact of alternative technologies' different permitting and construction lead times, and it impact these have on the performance of strategies under uncertain and noisy, AGREA's "Prespecified Pathway Program" was used to choose which technologies came on line in what future years. The PSP program steps through the a scenario's study period (2000-2024), and selects which power plants to build based upon *anticipated* future load growth, changes in the existing fleet of power plants, the desired mix of future power plants, and how well it has done in adhering to that mix in previous planning years.

Figure 1.3 shows how these two models are encapsulated in pre- and post-processing tasks where options and uncertainties are combined and fed to the capacity expansion (PSP) and power system operation (EGEAS) simulators. Information not used by EGEAS is retained and integrated with model results in the "attribute processor" spreadsheet (AttPro). A suite of command files or scripts allows the automated processing of scenarios in large batches. Management of scenarios is facilitated by their coded scenario names.

OVERVIEW OF SHANDONG ESS SCENARIOS

Table 1.1 shows the option-sets, individual options and their respective letter codes for the CETP ESS scenarios. Table 1.1 also shows the three generations of scenario sets analyzed by the ESS research team. Each option-set reflects a position in the scenario name, and each letter represents the option selected. For example the "reference scenario" BOC-CONPAS-FIB is comprised of the first option (and therefore letter) in each category, plus the mid-range uncertainty for electricity demand growth and fuel costs. Each choice of technology also includes assumptions related to the deployment or introduction of that technology into the province's electric sector with some operational assumptions. Sensitivities including no flue gas desulfurization technologies on smaller new conventional coal fired generation, windpower, biomass and waste-fired generation and several end-use efficiency and natural gas cost uncertainties are not reflected in Table 1.1.

The options and uncertainties shown were devised through individual and group dialogue with the CETP's Stakeholder Advisory Group (SAG) which was comprised primarily of State and Provincial representatives from various electric power, economic development and environmental ministries or state owned companies. Each stakeholder was also given a questionnaire that the ESS team used to help select and prioritize various technologies and uncertainties. These were then used to construct an "Initial Scenario Set" whose results were presented to the SAG in March of 2001. This set was then revised based upon the their comments and re-analyzed. Changes from the "Initial" to the "Revised" scenarios included switching to prepared coal in old generators only, looking at additional retirements versus sulfur scrubber retrofits of old power plants, a focus on Atmospheric Fluidized Bed Combustion (AFBC) versus Integrated Gasification Combined-Cycle (IGCC) clean coal technologies, additional natural gas options, a higher cost coal uncertainty reflecting the need to invest in coal transportation infrastructure, and the impact of cheaper natural gas.

Review of the Revised scenario set results showed that the IGCC performed better than AFBC due primarily to its higher thermal efficiency, and that additional unit retirements should be considered to tackle particulate emissions. This led to the a third "Refined" scenario set, which is the primary subject of the ESS chapter in the book, and from which the scenarios for Life Cycle Assessment, Environmental Impact Assessment and Multi-Criteria Output Integration Analysis were selected.

OVERVIEW OF SHANDONG ESS ATTRIBUTES

Table 1.2 lists the 242 attributes automatically calculated by the ESS's Attribute Processor. Grouped by their general function, these attributes show present value and future year "split" costs, power plant emissions, electricity demand and growth in generation, plus fuel consumption and coal transport, plus their changes over time. Such an extensive list allows the research team to identify the source of various cost and emissions impacts without returning to a scenario's source results.

TABLE 1.1: :Shandong ESS Scenario Components and Evolution

CETP ESS Scenarios	Total No. of Scenarios		**2,160**	**18,144**	**18,144**
	No. of Strategies		240	1,008	1,008
	No. of Futures		9	18	18
Option Set	Option		Initial	Revised	Refined
Existing Generation Options					
Retire/Refire	Base (50 MW & Smaller)	B	• 2	• 4	• 2
	Select Retirements	R	•	•	
	Scheduled Retirement at 40 Years	S		•	
	Scheduled Retirement at 35 Years	T		•	
	Select Retirements & Thirty-Five Years	D			•
Emissions Retrofit	None beyond Planned	O	• 2	• 1	• 2
	Select FGD Retrofits	U	•		•
Fuel Switch	Current Coal	C	• 2	• 3	• 3
	Prepared Coal in Existing Units Only	X		•	•
	Prepared Coal in All Conventional Coal Units	P	•	•	•
New Generation Options					
New Baseload/Intermed.	Conventional Coal Only	C	• 5	• 7	• 7
	Conv. Coal + IGCC Beginning 2012	L	•		•
	Conv. Coal + AFBC Beginning 2010	F		•	•
	Conv. Coal + NGCC Beginning 2015	M	•	•	•
	Conv. Coal + Must Run NGCC	R		•	
	Conv. Coal + Nuclear Beginning 2010	N	•	•	•
	Conv. Coal + NGCC + Nuclear	D	•	•	•
	Conv. Coal + NGCC + AFBC + Nuclear	K		•	
	Conv. Coal + NGCC + IGCC + Nuclear	T			•
Extra-Provincial Generation	None	O	• 1	• 2	• 2
	Natural Gas by Wire	A		•	•
Renewables	None	N	• 1	• 1	• 1
Peak Management	Moderate CTs (No LM)	P	• 2	• 2	• 2
	Load Management	L	•	•	•
Reserve Margin	Target (20%) RM	A	• 1	• 1	• 1
Efficient End-Use Options					
End-Use Programs	Current Standards	S	• 3	• 3	• 3
	Moderate Efforts (10% Cumulative Reduction)	M	•	•	•
	Aggressive Efforts (20% Cumulative Reduction)	G	•	•	•
Future Uncertainties					
Electricity Demand Growth	Slow Growth (≈4%/yr)	T	• 3	• 3	• 3
	Moderate Growth (≈5%/yr)	F	•	•	•
	Strong Economy (≈7%/yr)	S	•	•	•
Coal Costs (Delivered)	Business as Usual Coal	I	• 3	• 3	• 3
	Competitive Coal	O	•		
	Productive Coal	U	•	•	•
	Aggravated Coal	A		•	•
Natural Gas Costs	Base Gas (¥26/GJ)	B	• 1	• 2	• 2
	Low Gas (¥15/GJ)	F		•	•

Reference Scenario: BOC-CONPAS-FIB

TABLE 1.2a: Electric Sector Simulation Attribute Definitions

No.	**Name**	**Description**	**Example**	**Units**
(1)	Scenario	Scenario Name		
		Regional Costs		
(2)	TRCn	NPV Direct Costs Regional Direct	585.07	*(NPV-*
(3)	TICn	Industry Direct	530.23	*1999¥B)*
(4)	TRCi	Inflation Adj. Direct Total Direct	1381.43	*(1999¥B)*
(5)	TICi	Elec. Ind. Direct	1227.12	
		Unit Costs		
(6)	TRELa	Ave. Cost / Electricity Total Direct	0.401	*(¥/kWh)*
(7)	**TRUSa**	Ave. Cost / Electric Service Total Direct	0.363	*(¥/US)*
(8)	TRELc	Ave. Cost / Electricity Total Direct	5.01	*(¢/kWh)*
(9)	TRUSc	Ave. Cost / Electric Service Total Direct	4.54	*(¢/US)*
		Cumulative Stack Emissions		
(10)	CO2t	Carbon Dioxide	2074.85	*(Million*
(11)	SO2t	Sulfur Dioxide	8.21	*Tonnes)*
(12)	NOxt	Nitrogen Oxides	6.25	
(13)	PM10t	Partic. PM-10	3.81	
(14)	SolWstt	Solid Waste	152.00	
(15)	Limestt	Limest. / Sorbent	13.39	*(kT)*
(16)	H2OCt	Water Consump.	4.75	*(T.cu.m)*
		Change in Emissions - 2000-2024		
(17)	CO2p	Carbon Dioxide	43.45	
(18)	SO2p	Sulfur Dioxide	-64.95	*(%)*
(19)	NOxp	Nitrogen Oxides	-48.64	
(20)	PM10p	Partic. PM-10	-27.75	
(21)	SolWstp	Solid Waste	1.82	
(22)	H2OCp	Water Consump.	-52.50	
		Cumulative Emissions from Existing Units		
(23)	CO2ec	Carbon Dioxide	39.11	
(24)	SO2ec	Sulfur Dioxide	84.59	*(%)*
(25)	NOxec	Nitrogen Oxides	66.11	
(26)	PM10ec	Partic. PM-10	88.59	
		2024 Emissions from Existing Units		
(27)	CO2e24	Carbon Dioxide	12.10	
(28)	SO2e24	Sulfur Dioxide	70.55	*(%)*
(29)	NOxe24	Nitrogen Oxides	39.70	
(30)	PM10e24	Partic. PM-10	86.14	
		Peak Load and Electricity Demand/Sales Info		
(31)	PEAK24	2024 Peak Load	32387	*(MWs)*
(32)	PKGRW	Peak Growth	3.82	*(Δ%/yr)*
(33)	PKRD24	2024 Peak Red.	11382	*(ΔMWs)*
(34)	PKRDP24	2024 % Pk. Red.	-26.01	*(%Δ)*
(35)	SALES24	2024 Elec.Sales	183.52	*(TWhs)*
(36)	SALGRW	Sales Growth	3.82	*(%/yr)*
(37)	SALRD24	2024 Sales Red.	64.51	*(ΔTWhs)*
(38)	SALRDP24	2024 % El. Red.	-26.01	*(%Δ)*
(39)	CSALES	Cumul. Elec.Sales	3103.3	*(TWhs)*
(40)	CSALRD	Cumul. Savings	817.4	*(ΔTWhs)*
(41)	CSALPRD	Cumul. % Red.	-20.85	*(%Δ)*
		Growth in Generating Capacity		
(42)	GEN24	Capability 2024	40785	*(MWs)*
(43)	GENGRW	Capability Growth	3.32	*(%/yr)*
		% Existing/Committed Generation		
(44)	EGEN10	2010	67.19	*(% All*
(45)	EGEN15	2015	56.24	*MWs)*
(46)	EGEN20	2020	47.64	
(47)	EGEN24	2024	39.39	
(48)	NewGen24	Generation from NEW Technology - 2024	71.41	*(% GWh)*
(49)	**MatGen24**	Generation from Mature Technology Index - 2024	1.00	*(Index)*

TABLE 1.2b: Electric Sector Simulation Attribute Definitions

No.	Name	Description	Example	Units
		Reserve Margin		
(50)	AveRM	Average Res.Marg.	42.24	
(51)	MaxRM	Max Res.Marg.	63.00	*(%)*
(52)	MinRM	Min Res.Marg.	24.00	
		Changes in Unit Costs		
(53)	US-Ave	Unit Cost of Elec. Service Average % Change	-1.34	*(%/yr)*
(54)	US-Max	Max. Increase	2.44	
(55)	US-Min	Max. Decrease	-5.17	
(56)	El-Ave	Industry Cost of Electricity Average % Change	-0.81	*(%/yr)*
(57)	ElMax	Max. Increase	2.82	
(58)	El-Min	Max. Decrease	-4.14	
		NPV Component Component Costs		
(59)	GenDn	Generation Direct	368.13	*(NPV-*
(60)	DSMDn	DSM Direct	54.84	*1999¥B)*
(61)	OthDn	Other Ind. Direct	0.00	
(62)	SSCapRn	Supply-Side Capital Recovery	225.73	
(63)	SSRecRn	Supply-Side Recurring Recovery	304.50	
(64)	SSGenRn	Generation Recovery	112.26	
(65)	SSAllRn	Total Regional Capital Recovery	280.57	
		NPV Component Component Costs, cont.		
(66)	GenDnp	Generation Direct	62.9	*(% of NPV*
(67)	DSMDnp	DSM Direct	9.4	*1999¥B)*
(68)	OthDnp	Other Ind. Direct	0.0	
(69)	SSCapRnp	Supply-Side Capital Recovery	38.6	
(70)	SSRecRnp	Supply-Side Recurring Recovery	52.0	
(71)	SSGenRnp	Generation Recovery	19.2	
(72)	SSAllRnp	Total Regional Capital Recovery	48.0	
(73)	SSBorn	Total Supply-Side Borrowing	554.5	*(NPV¥B)*
(74)	**SSBorLn**	Levelized Supply-Side Borrowing	0.179	*(¥/kWh)*
		Inflation Adjusted Component Costs		
(75)	GenDi	Generation Direct	844.46	*(1999¥B)*
(76)	DSMDi	DSM Direct	154.31	
(77)	OthDi	Other Ind. Direct	0.00	
(78)	SSCapRi	Supply-Side Capital Recovery	504.75	
(79)	SSRecRi	Supply-Side Recurring Recovery	722.37	
(80)	SSGenRi	Generation Recovery	236.89	
(81)	SSAllRi	Total Regional Capital Recovery	659.06	
(82)	GenDip	Generation Direct	61.1	*(% of*
(83)	DSMDip	DSM Direct	11.2	*1999¥B)*
(84)	OthDip	Other Ind. Direct	0.0	
(85)	SSCapRip	Supply-Side Capital Recovery	36.5	
(86)	SSRecRip	Supply-Side Recurring Recovery	52.3	
(87)	SSGenRip	Generation Recovery	17.1	
(88)	SSAllRip	Total Regional Capital Recovery	47.7	
(89)	SSBori	Total Supply-Side Borrowing	1152.7	*(1999¥B)*
(90)	SSBorLi	Levelized Supply-Side Borrowing	0.371	*(¥/kWh)*
		NPV Recurring Costs		
(91)	PCOSTn	Production Cost	193.55	*(NPV-*
(92)	FCOSTn	Fuel Costs	142.78	*1999¥B)*
(93)	BOMn	Combined O&M	113.09	
(94)	VOMn	Variable O&M	50.76	
(95)	FOMn	Fixed O&M	62.32	
(96)	PCOSTnp	Production Cost	36.5	*(% of NPV*
(97)	FCOSTnp	Fuel Costs	26.9	*Industry*
(98)	BOMnp	Combined O&M	21.3	*1999¥B)*
(99)	VOMnp	Variable O&M	9.6	
(100)	FOMnp	Fixed O&M	11.8	

TABLE 1.2c: Electric Sector Simulation Attribute Definitions

No.	***Name***	***Description***	***Example***	***Units***
		Inflation Adjusted Recurring Costs		
(101)	PCOSTi	Production Cost	459.11	*(1999¥B)*
(102)	FCOSTi	Fuel Costs	358.03	
(103)	BOMi	Combined O&M	249.54	
(104)	VOMi	Variable O&M	101.08	
(105)	FOMi	Fixed O&M	148.46	
(106)	PCOSTip	Production Cost	37.4	*(% of NPV*
(107)	FCOSTip	Fuel Costs	29.2	*Industry*
(108)	BOMip	Combined O&M	20.3	*1999¥B)*
(109)	VOMip	Variable O&M	8.2	
(110)	FOMip	Fixed O&M	12.1	
		New Capacity Additions		
(111)	ICap10	Total 2010	10200	*(MWs)*
(112)	ICap20	2020	20300	
(113)	ICap24	2024	24720	
(114)	Peak10	Peaking Capacity 2010	0	*(MWs)*
(115)	Peak20	2020	0	
(116)	Peak24	2024	620	
(117)	Coal10	Conventional Coal 2010	7200	*(MWs)*
(118)	Coal20	2020	7200	
(119)	Coal24	2024	7200	
(120)	ClCl10	Clean Coal 2010	1500	*(MWs)*
(121)	ClCl20	2020	2100	
(122)	ClCl24	2024	2400	
(123)	NGas10	Natural Gas 2010	500	*(MWs)*
(124)	NGas20	2020	5000	
(125)	NGas24	2024	6500	
(126)	Nucl10	Nuclear 2010	1000	*(MWs)*
(127)	Nucl20	2020	6000	
(128)	Nucl24	2024	8000	
(129)	Wind10	Windpower 2010	0	*(MWs)*
(130)	Wind20	2020	0	
(131)	Wind24	2024	0	
(132)	BioAlt10	Biomass and other Alternatives 2010	0	*(MWs)*
(133)	BioAlt20	2020	0	
(134)	BioAlt24	2024	0	
(135)	SmDG10	Small & Distributed Generation 2010	0	*(MWs)*
(136)	SmDG20	2020	0	
(137)	SmDG24	2024	0	
		Percent of New Generation by Technology Class (2024)		
(138)	PeakP24	Peaking	2.5	
(139)	CoalP24	Conv. Coal	29.1	
(140)	ClClP24	Clean Coal	9.7	*(%-New)*
(141)	NGasP24	Natural Gas	26.3	
(142)	NuclP24	Nuclear	32.4	
(143)	WindP24	Wind- Power	0.0	*(%-New)*
(144)	BioAltP24	100 Biomass & Alt	0.0	
(145)	SmDGP24	Small & DG	0.0	
		Cumulative Generaton (TWh) by Fuel Class		
(146)	CmTTwh	Total TWh	3308.94	
(147)	CmCTwh	TOTAL Coal	2204.06	
(148)	CmRTWh	Raw Coal	1429.94	*(TWh*
(149)	CmPTWh	Prepared Coal	774.12	*-Busbar)*
(150)	CmWTWh	Washed Coal	0.00	
(151)	OlNGTWh	Oil and Nat. Gas	494.79	
(152)	NucTWh	Nuclear	591.71	
(153)	HyPSTWh	Hydro & P.Storage	18.39	*(TWh*
(154)	WindTWh	Wind & PV	0.00	*-Busbar)*
(155)	BAltTWh	Biomass & Others	0.00	

TABLE 1.2d: Electric Sector Simulation Attribute Definitions

No.	Name	Description	Example	Units
		Cumulative Generaton (% of Cumulative) by Fuel Class		
(156)	TCoalp	TOTAL Coal	66.6	
(157)	RCoalp	Raw Coal	43.2	
(158)	PCoalp	Prepared Coal	23.4	
(159)	WCoalp	Washed Coal	0.0	*(%)*
(160)	OlNGp	Oil and Nat. Gas	15.0	
(161)	Nuclp	Nuclear	17.9	
(162)	HyPSp	Hydro & P.Storage	0.6	*(%)*
(163)	Windp	100 Wind & PV	0.0	
(164)	BAltp	Biomass & Others	0.0	
		2024 Generaton (TWh) by Fuel Class		
(165)	CmTWh24	Total 2024	195.80	
(166)	TCTWh24	TOTAL Coal	68.29	
(167)	RCTWh24	Raw Coal	62.80	
(168)	PCTWh24	Prepared Coal	5.49	*(TWh*
(169)	WCTWh24	Washed Coal	0.00	*-Busbar)*
(170)	OlNG24	Oil and Nat. Gas	49.40	
(171)	Nucl24	Nuclear	77.19	
(172)	HyPS24	Hydro & P.Storage	0.92	*(TWh*
(173)	Wind24	Wind & PV	0.00	*-Busbar)*
(174)	BAlt24	Biomass & Others	0.00	
		2024 Generaton (% of Cumulative) by Fuel Class		
(175)	TCTWh24p	TOTAL Coal	34.9	
(176)	RCTWh24p	Raw Coal	32.1	
(177)	PCTWh24p	Prepared Coal	2.8	
(178)	WCTWh24p	Washed Coal	0.0	
(179)	OlNG24p	Oil and Nat. Gas	25.2	
(180)	Nucl24p	Nuclear	39.4	
(181)	HyPS24p	Hydro & P.Storage	0.5	
(182)	Wind24p	100 Wind & PV	0.0	
(183)	BAlt24p	Biomass & Others	0.0	
		Cumulative Fuel Energy Consumption (PJ) by Fuel Class		
(184)	CmTPJ	All Fuels	36418.17	
(185)	CmTCPJ	TOTAL Coal	24531.69	
(186)	CmRCPJ	Raw Coal	16256.87	
(187)	CmPCPJ	Prepared Coal	8274.83	
(188)	CmWCPJ	Washed Coal	0.00	*(PJ)*
(189)	OlNGPJ	Oil and Nat. Gas	3980.34	
(190)	NuclPJ	Nuclear	7906.14	
(191)	BAltPJ	Biomass & Others	0.00	
		Change in Fuel Energy Consumption (2000-2024)		
(192)	ChPJ	Change in All Fuels	184.05	*(Δ%)*
		Cumulative Fuel Energy Consumption (% of Total) by Fuel Class		
(193)	TCPJ24p	TOTAL Coal	35.81	
(194)	RCPJ24p	Raw Coal	33.38	
(195)	PCPJ24p	Prepared Coal	2.42	
(196)	WCPJ24p	Washed Coal	0.00	*(%)*
(197)	ONPJ24p	Oil and Nat. Gas	17.90	
(198)	NucPJ24p	Nuclear	46.30	
(199)	BAltPJ24p	Biomass & Others	0.00	

TABLE 1.2e: Electric Sector Simulation Attribute Definitions

No.	***Name***	***Description***	***Example***	***Units***
		Cumulative Coal Consumption by Type and Source All Coal (TMT)		
(200)	CoalTMT	TOTAL Coal	1032.71	*(Trillion*
(201)	RCTMT	Raw Coal	697.31	*Metric*
(202)	PCTMT	Prepared Coal	335.40	*Tonnes)*
(203)	WCTMT	Washed Coal	0.00	
(204)	BtMrTMT	Bitum. & Meager	1009.31	*(TMT)*
(205)	AnLgTMT	Anthr. & Lignite	23.40	
(206)	SDTMT	Shandong Coal	373.28	*(TMT)*
(207)	SxIMTMT	Shanxi & Inn.Mong.	653.90	
(208)	CmSDp	Percent Shandong	36.1	*(%)*
		Change in Coal Consumption (2000-2024)		
(209)	CoalTMTdp	TOTAL Coal	5.2	
(210)	BMTMTdp	Bitum. & Meager	7.8	*(Δ%*
(211)	ALTMTdp	Anthr. & Lignite	-93.5	*-TMT)*
(212)	SDTMTdp	Shandong Coal	-70.0	
(213)	SXIMTMTdp	Shanxi & Inn.Mong.	201.3	
		Cumulative Coal Transport by Source and Mode (Trillion Tonne-kilometers)		
(214)	CoalTkm	TOTAL Coal Transport	697.77	*(Tt-km*
(215)	SDMMTkm	Shandong MM	0.00	*Trillion*
(216)	SDRlTkm	Shandong Rail	26.10	*Tonnes*
(217)	SxMMTkm	Shanxi MM	0.00	*km)*
(218)	SxRlTkm	Shanxi Rail	230.14	
(219)	SxRSTkm	Shanxi Rail / Ship	431.84	
(220)	IMRSTkm	Inn.Mong. Rail / Ship	9.70	
		Cumulative Coal Rail Transport by Source and Mode		
(221)	CmRlTkm	Total Rail-km	537.51	
(222)	SDRlTkm	Shandong Rail	26.10	*(Tt-km)*
(223)	SXRlTkm	Shanxi Rail	503.99	
(224)	IMRlTkm	Inn.Mong. Rail	7.42	
		2024 Coal Rail Transport by Source and Mode		
(225)	RlTkm24	Total Rail-km	22.46	
(226)	SDRl24	Shandong Rail	0.51	*(Tt-km)*
(227)	SxRl24	Shanxi Rail	21.94	
(228)	IMRl24	Inn.Mong. Rail	0.00	
		Cumulative Coal Ship Transport by Source and Mode		
(229)	CmShTkm	Total Ship	157.99	
(230)	SxShTkm	Shanxi Ship	157.99	*(Tt-km)*
(231)	IMShTkm	Inn.Mong. Ship	0.00	
		Change in Total Coal Transport (2000-2024)		
(232)	**CmTkmdp**	Total Transport	212.0	
(233)	SDTkmdp	Shandong Total	-70.0	*(Δ% -*
(234)	SxTkmdp	Shanxi Total	338.7	*Tt-km)*
(235)	IMTkmdp	Inn.Mong. Total	-100.0	
		Change in Coal Rail Transport (2000-2024)		
(236)	RlTkmdp	Total Rail	140.8	
(237)	SDRlTkmdp	Shandong Rail	-70.0	*(Δ% -*
(238)	SxRLTkmdp	Shanxi Rail	232.7	*Tt-km)*
(239)	IMRlTkmpd	Inn.Mong. Rail	-100.0	
		Change in Coal Ship Transport (2000-2024)		
(240)	ShTkmdp	Total Ship	1046.1	*(Δ% -*
(241)	SxShTkmdp	Shanxi Ship	1781.9	*Tt-km)*
(242)	IMShTkmpd	Inn.Mong. Ship	-100.0	
	Bold	*Names = MCDA Criteria*		

An Overview of Shandong Province

Shandong is one of China's most highly populated and economically productive provinces. As one of several "bonded free-trade zones" along China's eastern coast, Shandong has achieved a high degree of export-based growth through a successful blend of both foreign investment and township and village enterprises (TVEs). One of China's thirteen state-approved bonded free trade zones, Shandong is also one of its most populous, rapidly developing and economically productive provinces. In addition to being a model for Chinese development, Shandong typifies the many energy and environmental challenges China faces as a whole. These include a historically overextended power system, large seasonal variations in water supplies and poor air quality, which Shandong is striving to reconcile along with its imperative for continued economic growth.

Shandong Geography

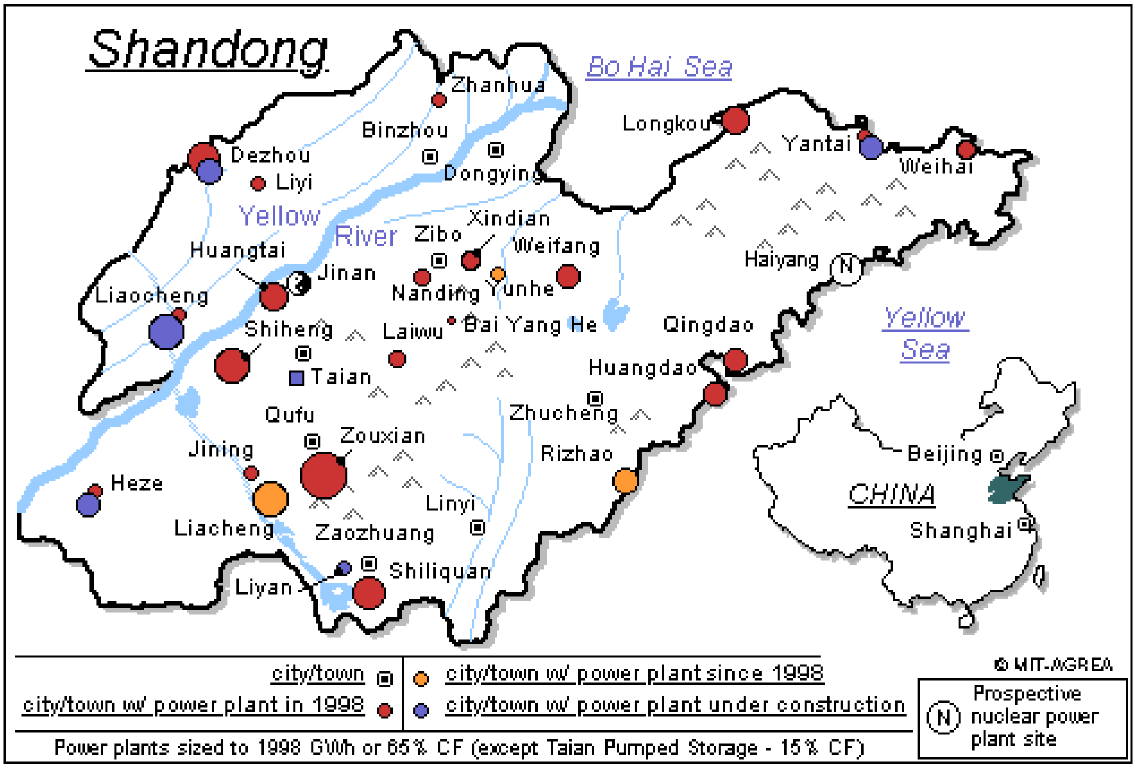
Shandong Province sits on China's northeastern seacoast, southeast of Beijing, between Tianjin and Shanghai. (See Figure 1.4) Shandong's population numbered over 86.7 million in 1995 (Chen, 1998), with a population density of 564 people per square kilometer (Sinton, 1996). Its capital city is Jinan, while its biggest city and predominant deep water port is Qingdao (Yantai SMR, 1999).

Shandong's land area covers 156,700 square kilometers, and is roughly 620 km from East to West, and 420 km from North to South. Its primary river is the Huang He (Yellow River) which runs southwest to north-central. The Huang He's delta is very dynamic, a result of large seasonal variations in flow and silt content, and flows into Laizhou Bay near Dongying municipality. The Yellow River Delta also contains the Shengli oilfields, China's second largest oil reserve (Business China, 1996). To the West of the Huang He is the Shandong peninsula, marked by a hilly range also running southwest to northeast (Zhang and Lin, 1992), the most prominent feature of which is Tai Shan, which at 1545m (5069 ft) is one of China's five most holy Taoist mountains (Atiyah, Leffman and Lewis, 1997). Along this axis, Shandong is roughly 750 km long (466 miles). Another water feature of great historical significance is the Grand Canal (Da Yunhe) which cuts across southwestern Shandong, and the cities of Liaocheng and Jining, on its way from Tianjin to Nanjing and Hangzhou.

Shandong's climate is temperate but mild, with temperatures in Jinan hovering near 1 C° in the winter months, between 21° and 28° C (70-82° F) in the summer months, and between 7° and 16° C (45-61° F) in the spring and fall. Jinan's heating season is relatively short at 4 months (World Bank, 1997). Jinan's rainiest season is summer, which accounts for 65% of its 68.5 cm of mean annual precipitation (Zhang and Lin, 1992).

Because Shandong is coastal and close to Japan and Korea, it is geographically well-situated for its export oriented economy. Primary exports include oil, textiles, chemicals, consumer products, paper, machinery, electronics and building materials (Singapore-Shandong Business Council, 1999). Shandong's gross domestic product ranked second among China's provincial GDPs in 1993 (Triolo, 1996).

FIGURE 1.4: Shandong Province and Its Principal Power Plants



Shandong's Electric Power Sector

Electricity Demand. By September 1994, every village in Shandong province had been electrified, and in February 1996 all households were electrified. (SEPCO, 1999). In 1997, rural electricity consumption (20 TWh) represented 24% of all electricity demand. Unmet demand in Shandong Province for 1996 was estimated to be 18 GW (Zou, 1996), but with a strong building program this gap appears to have been closed.

Electricity Supply. Recent statistics from Shandong's largest electric utility, Shandong Electric Power Group Co. (SEPCO) in Table 1.3 show that from 1978 to 1998 generation capacity in the province has grown from almost 2.8 GW to just shy of 18 GW, a 532% increase, making Shandong second largest province in terms of installed capacity.. Over the same period electricity sales increased from 15.4 TWh to 84.2 TWh, nearly a 450% increase in consumption.

TABLE 1.3: Electricity Consumption in Shandong

Year	Installed Capacity	Electricity Sales	
1996	14.2	79.3	
1997	16.2	84.2	6.2
1998	17.5	84.3	0.1
	(GW)	(TWh)	(Δ%)

(SEPCO, 1999)

Generation in Shandong is predominantly coal. For the 1996 generation listed in State statistical journals, only 40 GWhs were derived from hydropower. The SHANDONG ELECTRIC POWER GROUP CORPORATION (SEPCO) manages dispatch and transmission across the over 36,000 km of predominantly low-voltage transmission lines (Russo, 1999) that comprise Shandong's provincial grid (Business China, 1996). The Shandong grid is China's largest stand-alone provincial network. Headquartered in Jinan, SEPCO is a diversified conglomerate with business interests in construction, mining, real estate, manufacturing, tourism and telecommunications as well as electricity. SEPCO employs 66,000 people, and actively contributes to Shandong's economic, social and cultural development.

TABLE 1.4: Breakdown of Shandong Thermal Generating Capacity, 1996

Plant Size	**No. of Plants**		**Combined Output**	
0-49 MW	71	73.2	929	7.5
50-99 MW	2	2.1	128	1.0
100-299 MW	10	10.3	2004	16.3
300-999 MW	12	12.4	6868	55.7
>999 MW	2	2.1	2400	19.5
Total	97		12329	
	(No.)	(%)	(MW)	(%)

(State Statistical Bureau, 1996)

In addition to managing transmission and distribution in Shandong, SEPCO owns and operates the majority of its generating stations. Shandong's capacity has grown rapidly this decade, and SEPCO plans to further expand the system via construction of an integrated mining and electricity generating venture in the Heze coal field (SEPCO, 1999). The coal mines of Shanxi represent potential added capacity for Shandong, though construction of a mine-mouth power station to wheel electricity to SDPG were thwarted in 1995 for lack of sufficient water resources. Development of a proposed 300-km Yellow River transfer project was also tabled that year. Northern China's lack of water resources may be a significantly limiting factor in power development (Business China, 1995).

TABLE 1.5: SEPCO Key Operating Data (SEPCO, 1998 and 1999)

Revenue from Power Sales	32.07	(B Yuan, 1999)
Electricity Sales	71.04	(TWh, 1999)
Generating Volume	75.73	(TWh, 1999)
Coal Consumption	377	(g/kWh, 1998)
Average Utilization Hours	5012	(Hours, 1998)
	57.2%	(% of yr.)
500 KV Transmission Lines	739	(km, 1998)
220 KV Transmission Lines	742	(km, 1998)
Official T&D Losses	5.01%	(1999)
Effective T&D Losses	6.20%	(1999 Gen. Volume / Electricity Sales)

Shandong's Fuel Supply Situation

One of the key topics determining what range of resource options to consider, and whether fuel supply as well as electric supply and demand options will also need detailed consideration, is the diversity, availability and robustness of current fuel supplies. The following sections provide a brief overview of the primary energy supply categories. While Shandong has more indigenous fossil resources than most other provinces, due to the size of their population and economic output, fuel supply and transportation issues remain important.

<u>Coal</u>. While China's mainstay of coal production is Shanxi Province, several coal mining operations are located in Shandong. Yet, Shandong imported 43% of the coal it used from other provinces in 1994 (Zou, 1996) mainly Shanxi (Sinton, 1996). Coal mined in northern China is high in quality, with an average gross calorific value of 21 GJ/tonne, and less than 1% sulfur content, but significant ash content. Discussions with stakeholders indicated that new coal-fired power plants in Shandong would be supplied with extra-provincial coal.

<u>Oil</u>. With respect to China as a whole, Shandong has much more oil than natural gas or coal. For example, Shandong contributed 22.5%, 8.2% and less than 6% respectively to China's overall oil, natural gas and coal production figures in 1993 (Sinton, 1996).

<u>Natural Gas</u>. The U.S. Department of Energy's Pacific Northwest National Laboratory (PNL), the Energy Research Institute of China, and the Beijing Energy Research Center recently produced a report entitled "China's Electric Power Options: An Analysis of Economic and Environmental Costs." Though natural gas accounted for 2% of China's energy use in 1997 (Russo, 1999), according to PNL it could supply up to one-third of China's electricity needs by 2020. Significant investments in natural gas pipleline infrastructure are now being made, with pipelines from the North and West currently under construction. Currently Shandong is not one of the provinces to be supplied by these pipelines.

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CHAPTER 2: FUTURE FOSSIL AND NUCLEAR GENERATION TECHNOLOGY CHARACTERISTICS AND COSTS

INTRODUCTION

Economic expansion is driven by reliable and affordable access to energy; this is especially true in China, where rapid economic growth has been accompanied by large increases in electricity demand. In order to continue meeting this demand, China will need to generate more electricity in the future, a goal which can be accomplished through the construction of new fossil fuel and nuclear power plants, and the use of renewable energy sources. The increasing availability of new fuels and power generation technologies opens up a wide array of possible energy futures for China.

To explore these possibilities, we crafted a set of generation strategies that Shandong Province could possibly use to address environmental concerns as well as meet growth in baseload and peak electricity demand. This chapter presents basic assumptions regarding future fossil and nuclear generation technologies. While the exact cost and performance characteristics of future generation technologies are uncertain, through a review of the technical literature, and discussions with the CETP's Chinese research colleagues and stakeholder advisory group we believe the assumptions presented here are reasonable. They do *not* however represent *forecasts* of future costs and performance, however we hope they are reasonable in this regard as well.

The technologies covered in this chapter include:

- Sub-critical pulverized coal (PC)
- Atmospheric fluidized bed (AFBC)
- Integrated gasification combined cycle (IGCC)
- Conventional oil-fired generation
- Diesel generation
- Advanced combustion turbines (CT)
- Advanced combined cycle (CC)
- Advanced light water reactors (ALWR)
- Modular high temperature gas cooled reactors (MHTGR)

These technologies comprise the core set of future technologies used to construct future generation portfolios in the CETP Electric Sector Simulation (ESS) task. These alternative generation portfolios are then compared across several different "futures," (e.g. fuel price changes and the speed of economic growth). We chose to model new coal, natural gas, and nuclear generation technologies, although diesel, Oil 6 characteristics and cost were developed. Alternate generation technologies are discussed in the next chapter.

Prior to presenting the each class of generation technology, we describe some of the cross-cutting technological assumptions, namely sulfur, particulates and nitrogen oxides controls, solid waste generation, and cooling technologies.

Following this the basic assumptions for conventional coal, clean coal, oil, natural gas and nuclear generation are presented. The final section of the chapter presents the our technology availability assumptions for these technologies with regards to Shandong Province. All monetary values in the study are expressed in 1999 Yuan (¥) terms and the exchange rate is fixed to 1999 US$ at ¥8 to $1. We assume that cost escalation for construction follows inflation, and that financing of power projects uses a 7% weighted average cost of capital (WACC). This WACC is commensurate with the price of investment for recent private power projects undertaken in China and Shandong, and has been confirmed by our stakeholders as reasonable.

Each type of generating unit is characterized by several economic and performance parameters. Overnight, fixed operation and maintenance (O&M) and variable O&M cost assumptions capture all construction and non-fuel operating costs for new plants. Overnight costs, estimated per kW of installed capacity, represent the total expenditure needed to hypothetically build a unit overnight. This amount is then distributed over the plants construction period (given in Appendix A) to give an accurate picture of disbursements during construction.

Assumptions for fixed O&M are costs that are incurred regardless of how much a plant runs over the course of a year. These cost are divided by the plants average capacity in a year, and expressed in $/kW-yr. Itemized expenses include labor for operating the unit, supervisory labor, administrative overhead and payment for scheduled maintenance. Variable O&M includes all non-fuel costs associated with the operation of the plant, and is expressed in $/MWh or $/GJnet. Consumables such as makeup water for the steam system, lubricating oil and limestone for the FGD system are tallied here.

Thermodynamic performance characteristics are captured in our assumptions for plant efficiency, which we express as a percentage, defined as the ratio of electricity delivered to the grid (busbar MW) divided by total fuel energy input. These calculations are based on heat rates using lower heating values (LHV, in kJnet/kWh). The environmental performance of pollution abatement technologies are expressed as percentages of sulfur, particulates and nitrous oxides removed from fuel prior, during or after the combustion process. Our scheduled maintenance and equivalent forced outage rate (EFOR) assumptions determine maximum unit availability. Appendix A details this information.

Cross-Cutting Technological Assumptions

Sulfur Control Technologies

The removal and reduction of sulfur oxides from the emission streams of fossil fueled power plants is a top priority for the Chinese government. Massive levels of sulfur pollution have caused human health problems and environmental damage. To combat this problem coal and oil fired power plants can use sulfur scrubbing and capture technologies to reduce emissions. In coal units, the most common and economical are technologies that combine sulfur grabbing compounds, like limestone, with combustion and exhaust gases, called Flue Gas Desulfurization (FGD).

Our analysis considers four commercially available FGD technologies, listed below with their sulfur removal efficiency for relatively high ash Chinese coals:

- Wet Scrubber (WS) 90%
- Seawater Scrubber (SW) 90%
- Spray Dry (SD) 80%
- Furnace Sorbent Injection / LIFAC method (LIFAC) 80%

The sulfur removal efficiency of each FGD technology type varies with coal quality, the Ca / S molar ratio, furnace design and boiler size. (See chapter "Sulfur Controls on Existing and New Generation" for more detailed information.)

TABLE 2.1: *Sulfur Control Effects on Efficiency, Costs and Water Consumption*

Pulverized Coal Generation 300 MW	Average Efficiency LHV	Average Heat Rate LHV	Overnight Cost ¥8=$1	Fixed O&M Costs	Variable O&M Costs	Total Water Consumption
No Scrubber-OC	36.0	9732	4800	160	8	26.65
Wet Scrubber-OC	35.0	10288	5360	176	32	99.76
Seawater Scrubber-OC	35.0	10288	4992	176	16	26.65
Spray Dry-OC	35.5	10143	5200	176	32	44.93
OC = Once through cooling	(%)	(kJnet / kWh)	(¥99 / kW)	(¥ / kW-yr)	(¥ / MWh)	(m3 / GWh)
Change with WS	-1.0	556	560	16	24	73.11
Change with SW	-1.0	556	192	16	8	0.00
Change with SD	-0.5	411	400	16	24	18.28

As displayed in Table 2.1, wet scrubbers and seawater desulfurization increase auxiliary power consumption and therefore reduce plant efficiency by one percentage point in our modeling. The less energy intensive spray-dry sulfur scrubbing systems only reduce overall efficiency by 0.5% with lower O&M costs, but use 30% more limestone feed than wet scrubbers to capture the sulfur (Generation Task Force, 1995). Unlike retrofitted FGD, new units are assumed to have no capacity loss (unit de-rating) with the addition of sulfur controls because the design would account for the power losses. Wet scrubbers have the added benefit of producing gypsum as a usable by-product, while seawater scrubbers produce only a waste slurry with the added advantage of no limestone consumption.

PARTICULATE CONTROL SYSTEMS

In addition to sulfur pollution problems, parts of China also contend with health and environmental effects caused by particulates and power generation is one of the primary contributors. To mitigate the problem, all new oil, pulverized coal and AFBC generation units are modeled with electrostatic precipitators (ESP) and hot gas cleanup in IGCC units. ESP technologies use an electric charge to capture fly ash particles and commonly have around a 99% capture efficiency when burning high quality coals. In our analysis, ESP efficiency was modeled at 95% for units using raw high ash coals, and 97% for units using prepared coals. The captured material can often be sold for building material, but is accounted for in the model as solid waste. IGCC power plants control for particulates with an integrated gas scrubbing system (hot gas cleanup), which has a control efficiency of 95%. (See chapter "Particulate Matter Control on Existing and New Generation" for more detailed information.)

NITROGEN OXIDES CONTROL SYSTEMS

Nitrogen oxides can contribute to high concentrations of ground level ozone, which in turn have human health impacts. To address these concerns, all new units built in the ESS scenarios are modeled with NO_x mitigating combustion technology. NO_x is typically created when the nitrogen from both the fuel and the air is exposed to high temperatures for sustained periods of time during the combustion process. Pulverized coal units can reduce NO_x with overfire air (OFA) and low-NO_x burners (LNB). OFA redirects a portion of the combustion air from the burners to injectors above the top burner level. This inhibits NO_x formation by extending and delaying combustion times, thus lowering combustion temperatures. OFA also reduces the concentration of air in the combustion chamber. LNB designs reduce NO_x by decreasing oxygen in the chamber, reducing flame temperatures, and shortening gas residence time in the burner (EPA, 1995). AFBC and IGCC coal units are designed to have inherently lower combustion temperatures and do not need additional equipment to keep NO_x levels low, but may use water to keep combustion zones below NO_x forming temperatures. In this analysis, natural gas fired combustion turbines were assumed to have low- NO_x combusters which reduce NO_x formation, but not flue gas treatment.

SOLID WASTE

The use of coal for power generation requires enormous mass flows; fuel and sorbent inputs, ash and gypsum or sulfur outputs. The ESS developed a set of assumptions for solid by-products for each type of plant configuration. A sampling of wet cooled coal plants is outlined in Table 2.2:

TABLE 2.2: *Mass Balances for Coal Fired Generation*

Technology Name	Nameplate Capacity (MW)	Sulfur Removal Tech.	FGD/FBD Limestone Consumption • (kg/MWh)	Solid "Wastes" Total Solid By-Products (kg/MWh) • (X % Ash)	(kg/MWh) • (X % S)	Co-Products Gypsum (G) and Sulfur (S) • (kg/MWh)
Conventional Coal Technologies (Subcritical)						
Pulverized Coal	300			• 4.07	n.a.	
Pulverized Coal	300	WS	• 13.149	• 4.07	n.a.	• 22.50 (G)
Pulverized Coal	300	SW	n.a.	• 4.07	n.a.	n.a.
Pulverized Coal	300	SD	• 17.633	• 4.07	n.a.	• 27.00 (G)
Clean Coal Technologies						
AFBC	300	INT	• 21.286	• 3.92	• 25.00	
IGCC	500	INT	• 37.160	• 5.35	n.a.	• 2.718 (S)
WS = Wet Scrubber SW = Sea Water Scrubber SD = Spray Dry/Dry Scrubber INT= Integral to plant			Multiply by Weight Percent Sulfur	Multiply by Weight Percent Ash	Multiply by Weight Percent Sulfur	Multiply by Weight Percent Sulfur

n.a. - not applicable

WS requires a 1:1 Ca:S stoichiometric ratio; spray dry needs 1.4:1; and less chemically efficient AFBC requires more than a 2:1 ratio. Lower reaction efficiencies as described in the associated document, "Sulfur Controls on Existing and New Generation," explain these differences. Sulfur controls can also lead to useful by-products. Pulverized coal WS and SD systems produce gypsum and ash that can be used in concrete and road construction. IGCC units produce a high-quality sulfur from the clean-up of the acid gas, but require larger relative amounts of limestone sorbent (Maude, 1997).

COOLING SYSTEMS

To dissipate waste heat from power plant operation, each of the new thermal generation units is modeled with either a once through cooling (OC) system or a wet cooling (WC) system. Once through cooling configurations take advantage of a large, natural water source nearby as a thermal sink. For example, coastal plants can use circulating seawater to absorb the waste heat from power production, typically resulting in a 10° to 15° C rise in the discharged water temperature (Culp, 1991). The natural water supply in an OC system may also be used for surface condenser cooling. OC cooling systems are more expensive to build but have lower operating and maintenance costs, as shown in Table 2.2. WC systems consume local water by expelling waste heat via evaporation in cooling towers. While less expensive to construct, they have comparatively higher operational expenses, and consume much larger quantities of water. For our simulations we assume that wet cooling causes an efficiency reduction of 0.5 percentage points and adds 8 ¥/kW-yr to fixed O&M when compared with OC, as shown in Table 2.3.

TABLE 2.3: *Cooling System Cost and Performance*

Technology Name / *Based on: Pulverized Coal 300MW*	Average Efficiency LHV (%)	Average Heat Rate LHV (kJnet/kWh)	Overnight Cost ¥8=$1 (¥99/kW)	Overnight Cost ¥8=$1 ($99/kW)	Fixed O&M Costs (¥/kW-yr)	Variable O&M Costs (¥/MWh)	Total Water Consumption (m3/MWh)
Once Through Cooling	37.0	9732	4800	600	160	8	0.0267
Wet Cooling	36.5	9865	4704	588	168	8	0.7593
Change (OC-WC)	0.5	-133	96	12	-8	0	-0.7326
% Change OC to WC	1.4	-1	2	2	-5	0	-2749

Over the life cycle of a thermal plant, OC is less expensive to use than WC. We therefore assume that all units built near the coast in Shandong will have OC systems, including all nuclear units. River flow rates are typically too low in Shandong to site OC stations inland, even though use of OC inland would be favorable from an overall water-use perspective, so inland units are modeled with Wet Cooling.

FUTURE GENERATION TECHNOLOGIES

CONVENTIONAL COAL GENERATION

Sub-critical coal units currently provide 97% of the power in Shandong. Few of these units have pollution mitigation equipment beyond particulate controls, and do not prepare the coal before burning. This has lead to acute pollution problems for

Shandong and low operating efficiencies at the current generation of coal plants. To address this issue in the future, new pulverized coal (PC) generation is modeled with a number of different configurations that differ by cooling system, sulfur controls (e.g. flue gas desulfurization, FGD) and size (300 MW and 600 MW). We assume that all new units are built with electrostatic precipitators (ESP) and low NO_X burners (LNB) with overfire air (OFA), which is consistent with current Chinese policy.

Our base assumption is that all new conventional coal generation will be built with flue gas desulfurization (Wet scrubbers for inland units, sea water scrubbers for coastal units). As several units under construction appear to have FGD technologies, along with several FGD retrofits on existing units, this seemed like a reasonable assumption. Higher sulfur coal can be used with these new units, so that plant operators can maintain a diversity of fuel supply, which would not be the case if no FGDs were built, and the units were forced to purchase only lower sulfur coals. This assumption is of course subject to sensitivity analysis.

On the efficiency side, larger 600 MW pulverized coal units were modeled slightly better thermal efficiencies. We assume a one percent point advantage compared to 300 MW coal plants. Table 2.4 displays a representative list of PC units and clean coal units with various combinations of cooling equipment. A more comprehensive listing of performance and cost assumptions for all the technologies is included in Appendix A. Note that super-critical coal fired generation is not included in the list. In the development of the cost and performance assumptions, little information on super-critical coal units was found, nor was it raised by Chinese colleagues during the development of ESS scenarios.

TABLE 2.4: *Coal Generation Technology Cost and Performance Assumptions*

Technology Name	Nameplate Capacity	Cooling Water Method	Average Efficiency LHV	Average Heat Rate LHV	Average Heat Rate LHV	Overnight Cost (¥8 = $1)		Fixed O&M Costs	Variable O&M Costs
	(MW)		(%)	(Btu/kWh)	(kJnet/kWh)	(¥99/kW)	($/kW)	(¥/kW-yr)	(¥/MWh)
Conventional Coal Tech. (Subcritical)			(Net Energy to Grid-busbar)						
Pulverized Coal	300	OC	36.0	9481	10002	4800	600	160	8
Pulverized Coal	600	OC	37.0	9224	9732	4800	600	152	8
Clean Coal Tech.									
AFBC	300	OC	38.0	8982	9476	7200	900	240	32
AFBC	300	WC	37.5	9101	9602	7040	880	248	32
IGCC	500	OC	45.0	7584	8002	9600	1200	240	8
IGCC	500	WC	44.5	7670	8091	9600	1200	248	8

OC=Once through cooling WC=Wet Cooling

CLEAN COAL TECHNOLOGIES

Clean coal technologies can play an important role in helping Shandong reduce pollution and increase power plant efficiency. We model two types of units: atmospheric fluidized bed combustion (AFBC) and integrated gasification combined cycle (IGCC). The AFBC plants are 300 MW in size, 38% efficient and require no additional sulfur removal equipment. Instead, limestone is fed into the combustion chamber with the coal and fluidized by the injection of air. At 800-900°C the limestone calcinates to CaO and more easily captures the sulfur to form $CaSO_4$, which can then be disposed of as solid waste with the coal ash. The lower combustion temperatures of AFBC also inhibit the formation of nitrous oxides (McMullan, 1997). For its advantages, AFBC does come with a higher price tag. We assume an overnight cost of ¥7200/kW ($900/kW) for an AFBC plant fitted with a once through cooling system (Table 2.4).

IGCC units, at 45% busbar efficiency, are substantially more efficient than conventional pulverized coal plants due to the elevated temperatures of the gas turbine that increase cycle efficiency. An IGCC plant works by first gasifying the coal into fuel gas and char. The char is combined with limestone and quenched in water to form an inert glass like material. During gasification, sulfur, nitrogen and chlorine impurities are present in their reduced form and can be easily extracted using existing chemical separation techniques (McMullan, 1997). The fuel gas is cleaned and combusted in a gas turbine. The residual heat is used via a series of heat exchangers to reheat pre-combustion fuel gas products after its cleaning, and to produce steam for high, medium and low pressure turbines. By using hot gas cleanup (along with limestone during gasification), more than 99% of the sulfur can be removed from emissions while at the same time producing salable sulfur.

OIL FUEL GENERATION TECHNOLOGIES

The availability of oil in China is limited and available supplies are consumed primarily by vehicles or used as chemical feedstocks. As import levels and prices continue to rise, oil becomes a less likely candidate for widespread electricity production. Nevertheless, oil and diesel generators are well-suited for peaking and/or emergency backup applications. The Oil 6 steam generators we model are characterized by relatively low capital costs, ¥4000/kW ($500/kW), but have below average efficiencies (34%). We also model small, 3 MW diesel generators in this category, although they have the same drawbacks as oil plants (see Appendix Afor detailed information).

NATURAL GAS GENERATION TECHNOLOGIES

The prospective construction of a large natural gas pipeline to Shandong in the coming decades and the discovery and extraction of natural gas located in Bo Hai Bay adjacent to Shandong, has opened up new energy opportunities for the province. Natural gas could conceivably play an important role in the electricity future of Shandong, and to exploit this new fuel source we modeled two types of gas-fired units: advanced combustion turbines (CT) and advanced combined cycle units (CC). For the former, we assume a 155 MW CT unit with a 38% efficiency and ¥3200 per kW capital cost ($400/kW), as outlined in Table 2.5.

We assume all advanced combined cycle units have an efficiency of 58% based on the newest technological advances, and an installation cost of ¥4800 per kW ($600/kW). Lower maintenance costs, higher availability and reduced air pollution are additional advantages of CC systems. We model three size configurations, 250, 500 and 750 MW, and while there is a slight savings in O&M costs for the larger units, overnight costs per kWh are essentially constant in nature, with more turbine modules added to a site to reach the desired output. OC and WC overnight cost comparisons are assumed to mirror the pulverized coal plants with a ¥96/kW increase for OC. Natural gas for baseload power production (using CC) is not assumed to be available in Shandong until 2015, but we do allow for peak load CT units in 2008 because of the Bo Hai Bay gas supplies.

TABLE 2.5: *Natural Gas Technology Cost and Performance Assumptions*

Technology Name	Nameplate Capacity (MW)	Cooling Water Method	Average Efficiency LHV (%)	Average Heat Rate LHV (kJnet/kWh)	Overnight Cost (¥8=$1) (¥99/kW)	($99/kW)	Fixed O&M Costs (¥/kW-yr)	Variable O&M Costs (¥/MWh)
Adv. Combustion Turbine	155	CL	38.0	9476	3200	400	8	24
Adv. Combined Cycle	250	OC	58.0	6208	4896	612	96	4
Adv. Combined Cycle	250	WC	57.5	6262	4800	600	112	4
Adv. Combined Cycle	500	OC	58.0	6208	4896	612	88	4
Adv. Combined Cycle	500	WC	57.5	6262	4800	600	104	4
Adv. Combined Cycle	750	OC	58.0	6208	4896	612	80	4
Adv. Combined Cycle	750	WC	57.5	6262	4800	600	96	4

OC=Once through cooling WC=Wet cooling CL=Closed loop cooling

NUCLEAR POWER GENERATION TECHNOLOGIES

A third, baseload generation fuel source is nuclear. China has extensive reserves of uranium and the world market for nuclear fuel remains relatively low cost. We considered two types of nuclear plants, Advanced Light Water Reactor (ALWR) and Modular High Temperature Gas-Cooled Reactor (MHTGR).[1] The ALWRs were sized at 600 and 1000 MW with 33% efficiency and once through cooling. Both these technologies have high relative overnight costs, ¥12000 and ¥11200 per kW respectively ($1500 and $1400), and high fixed O&M, above ¥320/kW-yr ($40/kW-yr) (See Table 2.6 below). The Chinese are moving toward domestic manufacture of all major components for nuclear plants, which will lower these costs; however, long construction periods (8 years) and capital requirements tend to work against building ALWRs. However, air pollution concerns and the need to diversify the energy generation portfolio work in favor of installing nuclear capacity.

TABLE 2.6: *Nuclear Power Cost and Performance Assumptions*

Technology Name	Nameplate Capacity (MW)	Cooling Water Method	Average Efficiency LHV (%)	Average Heat Rate LHV (kJnet/kWh)	Overnight Cost ¥8=$1 (¥99/kW)	($99/kW)	Fixed O&M Costs (¥/kW-yr)	Variable O&M Costs (¥/MWh)
MHTGR	113	OC	45.0	8002	8000	1000	0	0
MHTGR	113	WC	44.5	8091	8000	1000	240	4
ALWR	600	OC	33.0	10911	12000	1500	248	4
ALWR	1000	OC	33.0	11079	11200	1400	328	4

OC=Once Through Cooling WC=Wet Cooling

[1] Based on stakeholder comments, ALWR's are used in all nuclear models, with MHTGR's used for sensitivity analysis in later scenarios.

We assume MHTGRs if pursued, will be erected in a pebble bed configuration, 113 MW in size. The graphite encased and moderated fuel this technology uses is more highly enriched than ALWR fuel (See "Non-Coal Fuels: Characteristics and Costs"), but the plant design uses a lower power density, 1/20th the density of an ALWR, to super-heat the helium gas (850°C). The higher temperatures achieved with a gas coolant translate into greater efficiencies when using high temperature turbines. We assume a 45% efficiency for MHTGR based on ESKOM and MIT design work (Nukem, 2000). MHTGR designs are also inherently safer than ALWR designs because of their greater fuel stability, and the natural convection that removes heat even if all coolant is lost in the core. MHTGR designs also require less active safety equipment and less overall containment, lowering the cost of construction to an estimated ¥8000/kW ($1000/kW) (Nicholls, 1998). A simplified design relative to that of the ALWR also translates into lower O&M costs, pegged at ¥240/kW-yr ($30) fixed and ¥4/MWh variable (see Table 2.6 above).

TECHNOLOGY AVAILABILITY IN SHANDONG

From a commercially available technology viewpoint, pulverized coal, diesel, oil and ALWR nuclear units are currently available for development in Shandong. We assume natural gas will not be available in sufficient quantities (i.e. via pipeline) for baseload power generation until between 2010 and 2015 in Shandong (Shan, 2000). We therefore assume that no new baseload natural gas combined cycle units will come on-line prior to 2015. However, based on stakeholder comments we assume advanced combustion turbines (CT) will have access to local gas supplies from Bo Hai Bay by 2008 to serve peak loads. Natural gas supply is not the only barrier to CT and CC use, as we assume high temperature turbines will have to be imported for the next decade, thereby raising their construction costs.

TABLE 2.7: *Generation Technology Availability in Shandong Province*

Technology Name	Nameplate Capacity (MW)	Lead Time Total Yrs. (Yr)	Tech. Availability In Shandong Order (Yr)	On-Line (Yr)
Diesel	3	1	1999	2000
Oil6	200	5	1995	2000
Advanced CT	155	3	2007	2010
Advanced CC	250	4	2011	2015
Pulverized Coal	300	5	1995	2000
AFB	300	5	2005	2010
IGCC	500	6	2006	2012
MHTGR	113	4	2000	2015
ALWR	600	8	2000	2010
ALWR	1000	8	2000	2010
Wind onshore	0.75	2	1998	2000
Wind offshore	1.50	3	2000	2003
Landfill Gas SI Engine	2.00	5	2000	2005

Clean coal technologies will also take time to deploy in Shandong. We assume the earliest an AFBC unit could come online in Shandong is 2010, and because IGCC represents the newest of coal-fired designs, it will not be commercially available to bring on-line in Shandong until 2012. Table 2.7 delineates all Shandong availability assumptions and the total lead times needed to bring a new unit online. This includes both permitting and design time, plus construction.

CONCLUSION

Shandong electricity planning will involve the careful management of existing units and the judicious choice of new construction technologies based on fuel costs, availability and environmental concerns. Power planners also want to increase diversification whenever possible to reduce single fuel risk. Power hungry Shandong will need to add several thousand MW of new capacity over the next decade, even with aggressive efficiency and demand side management efforts. Shandong is poised to meet these challenges with a broad array of power producing options.

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CHAPTER 3: FUTURE ALTERNATIVE FUELED AND RENEWABLE GENERATION CHARACTERISTICS AND COSTS

INTRODUCTION

The provision of adequate electrical energy is a complex balancing act between the environment, technology choice and economics. Environmental concerns and the massive pollution potentially caused by fossil fuel generation systems necessitate the consideration of alternative sources of generation. In China, the increasing availability of new fuels and power generation technologies has opened up a wide array of possible energy futures. In exploring these possibilities, we examined a set of alternative fuel and renewable electricity generation strategies that Shandong Province could possibly use to address environmental concerns while responding to future increases in baseload and peak electricity demand. These alternative generation portfolios are then compared across several different "futures," (e.g. fuel price changes and the speed of economic growth).

The potential use of renewable energy technologies in Shandong is explored by first examining the distribution and composition of renewable energy in Shandong and second the electricity production technology that can be employed to harness the resources.

The following resources are examined:

- Coal Bed Methane (CBM)
- Biomass
- Municipal Solid Waste (MSW)
  (Mass Burn, Standard Landfill, Bioreactor Landfill, and Anaerobic Digestion)
- Windpower
- Solar Electric
- Hydropower

As will be seen in the review of these technologies and their respective resources, only windpower and landfill gas were incorporated into Electric Sector Simulation (ESS) scenarios, as sensitivity runs to the scenarios used for life-cycle assessment, environmental impact assessment and multi-criteria decision support.

This document describes the adequacy of alternative fuels for grid-connected power production, and the technical and economic characteristics of the fuel conversion technology, as they apply to Shandong Province. Specifically, we examine the cost and environmental performance of new generation technologies as they might be deployed in China in the future. As there is little direct information on resources and technologies, as they might actually be applied to Shandong Province, the assumptions presented in this section must be viewed as approximations of future prospective generation options.

We drew upon a variety of literature, as well as recent reports and feedback from Chinese stakeholders. We were also able to incorporate regional adjustment factors for the economic and performance assumptions in our simulation for new units built in Shandong. All monetary values in the study are expressed in 1999 Yuan (¥) terms and the exchange rate is fixed to 1999 US$ at ¥8 to $1. We assume that cost escalation for construction follows inflation.

COAL BED METHANE

Coal bed methane (CBM) in China represents a huge energy resource for the country, but supply is concentrated in only a few major coal-producing provinces. Shanxi Province has an abundance of CBM, while Shandong, even though it produces large amounts of coal, has a relatively small amount of coal bed methane.

Table 3.1 displays the total resources available for China, Shanxi and Shandong. The "main areas" distinction is important because other figures include small reserves away from established coal seams that would be difficult to utilize economically. The "recoverable" label is meaningful for comparison because it represents the amount of CBM that can be economically extracted from the coalfields using current technologies.

TABLE *3.1: Coal Bed Methane Resources in China*

Location	Total Reserves	Recoverable Reserves
Shandong	6.93	*2.03
Shanxi	4941.52	1449.82
(Main Areas)	2394.52	426.03
China	14336.94	4206.39
(Main Areas)	4730.34	1387.86

* Calculated from Chinese Average Recoverability Rate
(Source: www.coalinfo.net.cn/coalbed)

Chinese sources prioritize CBM use in this order (Yi et.al. 1998):

1. Residential Fuel Gas
2. Industrial Fuel Gas
3. Chemical Feedstock
4. Power Generation

Due to the competing priorities for the CBM resource, the earliest that CBM would be available for large-scale power production is estimated to be 2010. Assuming CBM collection investments are made in the next decade, the most efficient use of CBM for electricity will most likely be direct or combined cycle combustion at the mine mouth to offset coal production power needs. This type of operation would help to reduce methane danger in the mine and mitigate greenhouse gas (GHG) emissions. In addition, poor grade coal slag (gangue) is often used in mine-mouth electricity plants, which can cause high levels of pollution, so any use of CBM that displaces the use of gangue can help to reduce mine pollution.

A few projects have been constructed in China, including one 1.5 MW plant built at the Laohutai Coal Mine in northeast China (Manchuria). The mine has an output of 3.2 million tonnes per year of coal and is estimated to have 63 million m^3 of CBM. The low heating value (LHV) of the 49% methane fuel is 12,865 kJ/m^3. The plant has blowers and a surge tank to supply the gas at adequate pressure to the gas turbine. (Kai, 2001) No capital costs were reported for this pilot plant.

As shown Table 3.1, the possibilities for electric power production in Shandong using CBM will remain limited. Bearing these factors in mind and the other CBM resource priorities, we estimate that total grid-deliverable electric power production is probably limited to 10 MW in Shandong. As such, no CBM electricity generation options were developed, although future options focusing on mine-mouth generation and consumption could be considered.

BIOMASS

SHANDONG BIOMASS RESOURCES

Current biomass resources in Shandong are predominantly agricultural residues such as wheat and corn stalks. Organized biomass utilization is about 10,000 tonnes per year. The rest of the agricultural residue is left *in situ,* or used on by farms for fuel, feed or cover. Table 3.2 provides a breakdown of the provinces biomass resources.

TABLE 3.2: *Shandong Biomass Resources* (Mt – Million Metric Tonnes)

Source: Category	Annual Production in China (Lin, 1998)	(Li, 1997)	(WREC, 1996)	Estimated Shandong Resource	Estimated Usable Biomass in Shandong
Crop Straw	479	600	450	81.81	9.82
Rice Husks	15		15	0.08	0.01
Sugar Cane	65		67	0.00	0.00
Forest Residue	18		15	0.00	0.00
Waste Water		50,000	18,252	1,369	

Notes: Only 12% can be used for energy (WREC, 1996). Estimates calculated using information from the 1999 Shandong Statistical Yearbook and WREC resource estimates.

Shandong does have 32,846 m^3 of wood biomass available, (Li et.al. 1997) which is not a sufficient quantity to contribute to large-scale electric power generation. Wood processing facilities however, can capture this resource for cogeneration. Therefore the best option for grid-connected power generation is to use biomass and municipal waste for gasification, an option discussed in the next section.

MUNICIPAL SOLID WASTE

Residential and municipal solid waste (MSW) is a growing problem in China. Already a serious environmental concern in the OECD countries, proper landfill management will be an important part of Chinese efforts to safeguard ground water and soil quality. Landfills are also responsible for large amounts of methane production. To control methane, four different strategies are available: the incineration of waste before it decomposes; the collection and direct use of methane for uses such as industrial process heating; the collection and flaring of methane; and the use of landfill methane for electricity production. Our analysis concentrates on this last option and its cost of implementation as compared to the costs of a standard landfill without electricity production facilities.

The disposition of urban waste in China in 2000 is predominately surface dumping or shallow, primitive landfills, which account for 79% of total tonnage. The remainder is placed in deeper landfills, the vast majority of which have little or no containment. (Li et.al. 1997) We assume that the Chinese will confront the MSW problem by constructing modern landfills and that with advanced planning, power optimizing bioreactors can be used to harness the MSW as a resource. In this section, Chinese MSW quantities and chemical properties are examined followed by an analysis and description of MSW incineration, landfill design and gas collection parameters. Finally, methane to electricity conversion technology is considered.

SHANDONG POPULATION, INCOME AND SOLID WASTE PRODUCTION

The Chinese hope to increase the sanitary landfill of waste to protect land and water quality, and the urban areas will be the first area of focus. Population growth and the level of economic development determine the amount and types of urban waste. The population of Shandong is about 26% urban, and these areas are the best source for concentrated MSW and its economical collection. Table 3.3 displays a detailed breakdown of population by district and the percentage living in urban areas in 1999.

TABLE 3.3: *Shandong Population Breakdown by District*

District	Total	Agricultural		Non-Agricultural	
Binzhou	3.57	2.87	80.5	0.70	19.5
Dezhou	5.27	4.28	81.2	0.99	18.8
Heze	8.32	7.13	85.7	1.19	14.3
Jinan	5.54	3.28	59.2	2.26	40.8
Jining	7.79	6.02	77.3	1.77	22.7
Laiwu	1.22	0.84	68.6	0.38	31.3
Liaocheng	5.51	4.68	84.9	0.83	15.1
Linyi	9.88	8.13	82.2	1.75	17.7
Qindao	7.00	4.45	63.6	2.54	36.4
Rizhao	2.74	2.12	77.3	0.62	22.6
Taian	5.36	3.85	71.9	1.51	28.1
Tonying	1.69	1.00	58.9	0.69	41.0
Weifong	8.36	6.28	75.2	2.07	24.8
Weihai	2.46	1.67	67.8	0.79	32.2
Yantai	6.43	4.50	70.0	1.93	30.0
Zabo	4.04	2.30	57.0	1.73	43.0
ZaoZhuong	3.55	2.35	66.3	1.19	33.6
1999 Total	88.72	65.75	74.1	22.95	25.9
	(Millions)	(Millions)	(%)	(Millions)	(%)

Rapid urbanization in China, with projections of 15% per decade moving to urban areas, may cause greater MSW production. To keep our energy estimates conservative we exclude urbanization factors, which would likely increase the total urban MSW. However, we also do not consider any future wide scale recycling programs, which could have the opposite effect. Rising income MSW consequences, which are dependent on economic growth and therefore highly variable, are accounted for by modeling a 10% mean growth rate in MSW volume from 2000-2014 and then a slower 5% mean rate from 2015-2024. The growth rate is multiplied by a noise factor to capture the variability of the economy.

Income levels not only have a direct affect on the amount of urban waste produced per person, but also on the composition of urban waste. Urban waste can be categorized into combustibles, recyclables, organics, and inorganics. Combustibles typically consist of paper, cardboard, wood, and plastics. Recyclables include glass and metals, and some combustibles in developed countries where paper products are removed by garbage scavengers. Food scraps, food waste, and yard waste make up the organics. Non-wood building materials, such as concrete, coal ash and street dirt account for most of the inorganics in the waste stream. The mix of urban waste largely dictates the application of energy technology. Higher income countries tend to have greater levels of paper and plastic combustibles while developing countries' waste has a higher concentration of organic foodstuffs and inorganic building materials. This distributional effect is illustrated in Table 3.4.

TABLE 3.4: *Income Effect on Urban Waste Composition* (Ashworth, 1996)

Country Income Level	% Combustible	% Recyclable	% Organic	% Inorganic
High (US, Europe, Japan)	45-55	10	10-30	10-30
Middle (Thailand, Mexico)	20-40	8-10	40-55	3-10
Low (Peru, India)	10-30	2-3	25-55	35-45

CHINESE MSW CHARACTERISTICS AND TRENDS

Table 3.5 quantifies the waste in China and then estimates the total in Shandong per capita, which is assumed to be 0.35 tonnes / year.

TABLE 3.5: *Landfill Waste Resources Estimate in Shandong*

City	Residential Refuse	Non-Agricultural Population	Per Capita MSW
Beijing	4.40	6.97	0.63
Tianjin	1.80	5.08	0.35
Shanghai	3.72	9.22	0.40
Qingdao	0.68	2.49	0.27
Northern China			0.62
Southern China			0.35
Shandong Urban Estimate	8.04	22.96	0.35
	(Mt / yr)	(Millions)	(tonne / yr)

The total amount of waste generated in Shandong in the base year 2000, is estimated for modeling to be 7 million tonnes. Composition changes brought on by higher incomes are not added into ESS modeling assumptions, but are likely to increase the amount of energy that can be extracted from the waste stream.

The organic content of MSW in Shandong is approximately 30%; food waste in refuse makes up most of the organic content, while ash from solid fuels makes up a large percentage of the inorganic content. In the urban areas where gas is used for cooking and heating, inorganic content is lower. This is especially true in cities in northern China, where the organic content in refuse may be over 90% in buildings with central heating and gas. (Li et.al. 1997) This is less frequently the case in Shandong where gas use is less pervasive. The other important characteristic of MSW is the moisture content, which affects the heating value for incineration. The water weight must be subtracted from the MSW tonnage to calculate methane production potential.

The moisture content of mix solid refuse is defined as: weight of water in waste/(weight of water + weight of solid in waste). The moisture content of mixed refuse is about 10-30% in China, but accounts for 40-50% of the weight of organic waste. (Ecom, 1980) In highly urbanized cities, the high-moisture food content in organic refuse is relative low, thus the moisture content of refuse is lower. On average, total Chinese MSW is approximately 15% moisture, as shown in Table 3.6.

TABLE 3.6: *Chinese MSW Characteristics*

Percent Organics:	30%
Calorific Content:	4,186.8 kJ/kg
Moisture Content:	15%

Table 3.7 outlines the waste composition of two cities in northern China with similar economic and income conditions as Shandong's major cities. These were then used to estimate the content of Shandong waste.

TABLE 3.7: *Percent Waste Composition by Category* (Li et.al. 1997)

Composition	Beijing	Tianjin	Shandong*
Food	27.0	23.0	25.0
Paper	3.0	4.0	3.0
Plastics	2.5	4.0	3.0
Fiber & Wood	0.5	0.0	0.5
Ash	63.0	61.0	62.0
Glass	2.0	4.0	3.5
Metal	2.0	4.0	3.0

(* estimates for modeling)

Table 3.8 adds depth to this analysis by describing what the anticipated chemical composition of a "typical" MSW stream in Shandong might be.. The composition is important for estimating the total gas production capability of the waste if placed in a controlled, bioreactor landfill site, a process described later in this section.

TABLE 3.8: *Chemical Composition of Shandong MSW* (Li et.al. 1997)

Waste Category	Carbon	Hydrogen	Oxygen	Nitrogen	Sulfur	% of Total	% of Organic
Food	43.52	6.22	34.50	2.79	0.30	25.0	71.0
Paper	40.37	5.96	39.01	20.30	0.30	3.0	9.0
Plastics	82.90	13.20	0.96	0.30	0.30	3.0	9.0
Fiber	48.36	5.58	39.59	0.30	0.30	0.5	1.0
Wood, Glass	40.54	5.85	33.34	1.66	0.30	3.5	10.0
Total	46.40	10.22	31.97	3.93	0.30	35.0	100.0

MUNICIPAL SOLID WASTE FUEL AND ENERGY CONVERSION TECHNOLOGIES

Direct Combustion of MSW

Municipal solid waste can be burned in a combustion chamber that heats water in a conventional boiler. Steam from the boiler drives an electric turbine that provides process heat to local industry or can be used to pre-heat the fuel. Remaining solids are recollected and sent to a landfill. Off-gases are run through a scrubber to eliminate particulates. Heavy metals and toxic organics may be removed with pollution control devices, and incombustible solids are land filled. Inert matter must be removed from incoming waste streams to protect the integrity of the equipment and maintain efficiency.

The percentages of combustibles in the waste stream largely determine the most suitable combustion generation technology. Waste streams with 45-55% combustibles have heat contents of 11,000 – 13,000 kJ/kg, which allows these streams to maintain sustained combustion in mass burn waste energy plants. Mass burn plants require heat contents of at least 7000 kJ/kg to sustain combustion. Low combustible waste streams with 15% to 30% combustibles have heat contents ranging from 4000 – 7000 kJ/kg. Shandong waste has approximately 4200kJ/kg heat content due to the low paper and plastic content and high concentration of inorganic, inert matter.

In addition to waste composition, moisture content also affects heat content. Sustained combustion requires that enough energy is generated to allow for the evaporation of water and the maintenance of sufficiently high temperatures. This condition is often difficult to consistently achieve in tropical to sub-tropical climates where heavy rains send moisture contents soaring as high as 80%, well beyond the physical capability of mass burn units.

Taking into account only the content of waste stream, mass burn units lend themselves for use in highly developed countries with only moderate levels of seasonal precipitation. Waste streams with high organic content and moisture levels are suitable for decomposition technologies such as landfill gas, bioreactors, and anaerobic digestion. Unfortunately, no technologies exist for extracting energy from inorganics, the most prevalent content matter of Chinese waste streams.

Therefore, ESS estimates that Shandong cannot produce significant power from burning MSW, because the poor burning characteristics of the waste (low calorie value) and high percentage of inorganics. Combustion and conversion are therefore economically untenable (see Table 3.8). The economics of a MSW plant are outlined in Section V.

Standard Landfill Gas Production

Wastes in standard landfills, defined as lined and soil-capped installations, undergo slow rates of anaerobic decomposition. This decomposition produces landfill gas (LFG) consisting of 40% to 50% methane that can be captured using a gas collection system and used for small-scale electricity generation or heating. Recently closed standard landfills produce methane gas at the highest rates in the first 5–20 years after waste placement, but will continue to produce methane and other gases for 30 more years at declining rates. Carbon dioxide (30-40%), nitrogen (10-20%), and other trace gases (<2%) comprise the non-methane gas components. Gas volume ranges widely from 1 to 7 m^3 per year per tonne of dry waste (US waste composition), which translates into 55–100 m^3 of methane per tonne of dry waste over the course of the 10–20 year lifetime landfill gas extraction. (Ashworth, 1996) The energy content of gas can vary from 7,500 – 22,000 kJ/m^3, but can be upgraded to 23,000 – 26,000 kJ/m^3 by removing water vapor and carbon dioxide. The organic and moisture content of the waste and design of the landfill have the largest impact on gas yield and heating content. We assume that methane from landfill gas will have a low heating value (LHV) of 36 MJ/m^3 (50 MJ/tonne) and a carbon content of 75% by weight.

Typical landfill gas utilization techniques involve sinking large diameter (0.6 – 1.0 m) perforated pipes to 90% of the landfill's depth. A partial vacuum is applied to the system of pipes to extract the LFG. Gas collection systems that are retrofitted to existing landfills often have low collection efficiencies, approximately 30% of ultimate methane production; however, pre-designed systems can more than double this rate. Once extracted, the LFG can be fed into a boiler, diesel engine or natural gas engine; or it can be upgraded to pipeline quality and distributed to homes and businesses. The total system for landfill gas recovery is a well-developed technology that has expanded rapidly in the US and Europe during the last two decades, partly due to public subsidies.

In addition to producing methane, which is utilized as an energy source, landfills also generate a leachate that can contaminate groundwater supplies if it permeates the plastic lining of the landfill. The leachate is caused by precipitation filtering through the waste and draining away from the site if unabated by synthetic or geological (clay) barriers.

Bioreactor Landfill Gas Production

Bioreactor landfills are an extremely promising development in landfill design that optimizes methane production and recovery. The gas composition and properties remain unchanged, but gas production and collection can be increased significantly. Full-scale bioreactor trials showed more gas production, with greater collection efficiency for two main reasons. First, gas collection systems are integrated into the design from the very beginning and second, leachate collection and recirculation keeps the waste cell moist while at the same time delivering water dissolved organic material to add to the decomposition reaction.

Full-scale bioreactor landfill studies began in the US in the 1980s, most notably at a six-cell site in Mountain View, California. These tests revealed several advantages in addition to the leachate control. Rapid decomposition of waste allows for the extraction of 90% of the potential methane within the first 8-10 years of operation; normal landfills take up to 50 years to extract this amount of methane. The bioreactor cells can then be emptied and refilled at the end of the 8-10 year decomposition process. This design feature will help to reduce the total amount of land needed for waste management.

In the Mountain View study, landfill gas production rates ranged from 0.7 to 0.16 m^3/kg of dry waste (or 40–90 m^3 methane/ tonne of dry waste), and ultimate methane gas yields of 230 m^3/MT dry refuse. (Rinehart et.al. 1998) A typical US landfill gas project in which there is no leachate recycling and in which the gas collection system is retrofitted onto a traditional sanitary landfill, yields 4-5 cubic meters of landfill gas/year/dry tonne of waste for a period of 10–20 years. A well-designed bioreactor test cell has produced gas at 2–5 times the rate of a conventional landfill. This high level of gas production may be particularly important for developing countries' urban areas, where new bioreactor landfills could be designed to provide landfill gas for power generation, for district heating, or for industrial boiler fuel.

For ESS modeling, we assume a conservative ultimate methane yield of 200 m^3/tonne of dry organic MSW (the latter being defined as the mass remaining after the inert inorganics and water weight have been subtracted, or 18%). By this calculation, each million tonnes of waste produces 9.25 MW-yr of electric power. The ESS assumes the use of a bioreactor plant that is constructed as part of a landfill management strategy, and we therefore account only for additional costs of electricity production, gas treatment (pressurization and filtering) and leachate recirculation. Gas and leachate collection systems are not included in our cost estimates. The overnight cost for a bioreactor landfill is assumed to be $650/kW after applying a 33% discounting factor for Chinese costs as compared to western figures, which we estimate at approximately $1000/kW from EPA documents. (EPA, 1999)

<u>Bioreactor Site Design</u>. Bioreactor sites are designed as individual cells containing 0.25 to 1 million metric tons of wet urban waste, with systems for recovering leachate from the bottom of each cell and re-circulating it back to the top of the cell. The footprint of the installation depends on waste depth, waste compaction and local hydrological/geological conditions. The Pecan Row Landfill in Georgia is an instructive example. This 39 hectare (ha) site is designed to fill 10 individual cells, 1.5 ha in size, with one constructed every seven months. The waste is filled to an 18m depth, giving the site a 540 metric ton/day capacity. The design incorporates a synthetic liner and a leachate collection system. (EPA, 1999)

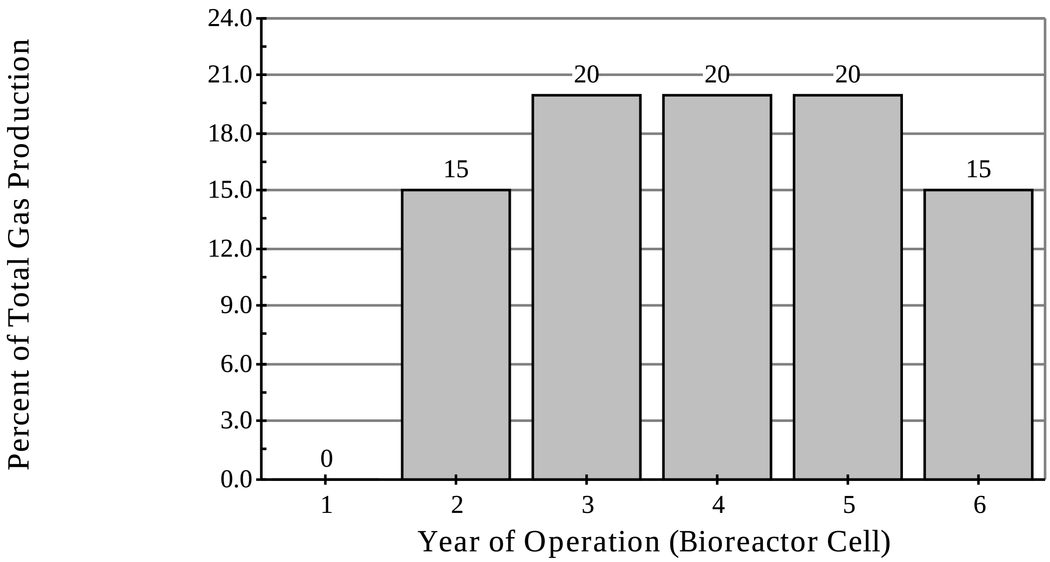
<u>Leachate Re-Circulation</u>. The recycling of the leachate in a bioreactor serves four functions. First, capturing the leachate, which normally has high levels of biological and chemical pollutants, prevents groundwater contamination. Second, re-circulation keeps the waste wet, a favorable condition for bacterial decomposition and methane production. Third, leachate that is added back into the waste pile delivers the dissolved organic material to the cell to add to the decomposition mass. Fourth, the need for other leachate treatment is reduced because the micro flora in the cell acts as a biological filter.

The recirculation function can be accomplished by adding perforated pipes to the bottom of the landfill; to prevent blockage, pebbles or other liquid porous material surrounds the pipes. The gravity-collected leachate is then pumped back to the surface and spread over the top of the waste pile, or on an adjacent cell, depending on the level of decomposition. To accomplish re-circulation, surface spraying, horizontal and vertical injection and cell capping pond methods have all been used. ESS models injection methods as the most promising for Chinese application because of the lower life cycle costs and higher absorption rates that result.

<u>Gas Collection System.</u> The methane gas is collected using perforated polyvinyl chloride (PVC) pipes placed vertically in the waste pile. A slightly lower pressure is created in the pipes to draw the gas to the cleaning and pressurization plant, but care is taken to make sure that air is not drawn into the waste pile by extracting methane too rapidly, a process which could raise oxygen levels and reduce anaerobic methane-producing conditions. We assume that 67.5% of the total methane produced is collected. This is the product of the gas produced within the MSW cell residence time window of seven years (90% of total production) times the collection efficiency of the system (75%). (Rinehart et.al. 1998) The timing of gas production is also an issue; we assume a one-year delay from cell completion to the

beginning of useful gas production. The year by year production of gas is given in Figure 3.1.

Figure 3.1: *Bioreactor Cell Gas Production by Year* (% of total production / yr)



<u>Gas Filtering, Condensation Control and Pressurization</u>. Landfill gas has small amounts of impurities and some moisture content requiring LFG cleanup and dehumidification, which increases engine performance and efficiency and reduces wear on engine parts from dirty gas. Mechanical filters and desiccators can be used to solve this problem. Depending on the engine type, gas pressurization may be needed, but in the case of internal combustion (IC) engines, no additional pressure is required.

Electricity Production from Bioreactors

Large-scale operations, more than 3 MW at one site, are ideal for using the higher efficiency combustion turbines but would need higher gas pressures to operate. For sites smaller than 3 MW, the modular and more easily maintained spark ignition IC engine, such as the 1 MW CAT 3516, are ideal. With efficiencies of 30%, these types of engines are reliable, and can be maintained by local machinists. High availabilities (90% or greater) make these units a solid contribution to the baseload power supply. ESS assumptions yield a sizable amount of power production from this engine type, as displayed in Figure 3.2.

Bioreactor power production is a fuel-following source of power. We assume that IC engine plants are installed as the fuel becomes available, thus accounting for the lag and difference between the maximum power from fuel curve, and the power from installed capacity. ESS bioreactor assumptions are summarized in Table 3.9.

FIGURE 3.2: *Bioreactor Power Production, by Fuel and Installed Capacity*

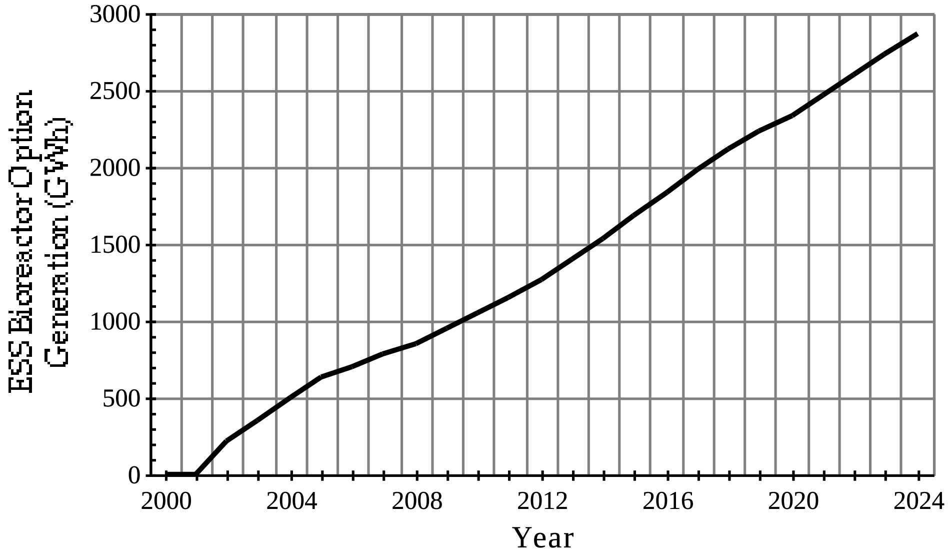


TABLE 3.9: *Bioreactor Power Plant Design Assumptions*

Methane	200	m^3 / tonne of Dry Organic MSW
Dry Organic MSW	18	wgt. % of Total MSW (China)
Heating Value of Methane	36	MJ / m^3 (LHV)
Percent of Methane Collected	67.5	%
Spark Ignition Engine Efficiency	30	%
Annual Generation	9.25	MW-yr / Million Tonnes MSW

ANAEROBIC DIGESTION

Anaerobic digestion is another bacterial process for methane production that uses vegetable matter, manure or sewage as a feedstock. A well-functioning digester produces a gas stream of 50%–70% methane, 30%–50% carbon dioxide and trace gases (< 1%), with an energy content of 18,000 to 26,000 kJ / kg. Anaerobic digestion has been used in sewage treatment since the 1930s, but has gained popularity in developing countries within the last 20 years to handle agricultural waste and sewage. Bio-gas yields range from 10 to 200 m^3 per tonne of organic waste depending on the design and feedstock materials.

The large variations in yield are also due to the differences in operational conditions and management. Anaerobic digestion requires significant process control to maintain stability and efficiency. The living microorganisms can be easily killed by unfavorable conditions such as undesirable temperatures, chemical contaminants in the incoming waste stream, pH upsets, poor mixing, or a high feed rate.

Two general types of anaerobic digesters exist, long residence time and short residence time. Short residence time digesters process wastes in a few hours to a few days, but must be carefully managed. They are primarily used for treating slurries from food processing, agriculture and sewage. Long residence time digesters process waste within two to four weeks, requiring less management and inspection, using higher solids wastes such as food wastes and manure. This option is practical for Shandong province, but the gas resources are better used for local heating and cooking, rather than for electricity generation. The need to collect large quantities of material also make it impractical for large scale power plants, and thus anaerobic digesters are not modeled in the ESS.

WINDPOWER

Windpower worldwide has achieved tremendous technological and economic maturity in the past two decades. Decreasing capital costs and more robust wind turbines have opened up a multitude of applications for windpower, from grid-connected to remote generation. In 1999, 12 GW of grid-connected windpower was installed worldwide (a 550% growth from 1990) (McGowan and Connors, 2000); however, a variety of institutional and technological problems are thwarting progress. Wind resources are poorly documented for specific locations and for seasonal changes, particularly in developing nations. Such detailed information must be known before serious wind investment can take place in a country. In addition, because wind is non-dispatchable and normally less that 35% available, power planners must be able to either store the windpower (which has efficiency losses) or have a large grid to feed the power into. Interconnection and the decreasing costs of fossil fuels (in real terms) over the past 10 years has also slowed the adoption of windpower, where other policy measures (e.g. subsidies) were not in place.

The economical use of windpower is determined by the wind resource, topography and the comparative price of electricity of a region. In China, the time may be right for a program of using windpower for grid-connected applications. The most exploitable wind resources in China are the southeast coast and the high desert steppes in the northwest. However, windpower shows great potential for widespread use in Shandong and therefore may help to displace fossil fuel emissions. Both windspeed and topography are in Shandong are favorable to windpower, especially along the peninsula and offshore. Table 3.10 summarizes the total on-shore capacity for Shandong, including its islands.

TABLE 3.10: *Shandong Land-based Wind Resources at 10m*

(Lew, 2000; Junfeng et.al. 1997)

Shandong Wind Quality	
3 m / s	4000-5000 hrs / yr
6 m / s	1500-2200 hrs / yr
Energy Density	150-200 w / m^2
Total Land Based Resource	3940 MW

Chinese and international sources have estimated the total land-based wind resource in Shandong to be 3940 MW, which is calculated from the scattered locational wind data and historical meteorological information. We expect that offshore wind can be utilized as well, thus the final resource is well above 4000 MW. By using large turbines (1500 kW and above) and taking advantage of reduced fatigue and better power from the more constant winds, the offshore option is modeled in Electric Sector Simulation strategies is allowed to grow to 3000 MW by 2024 and thus displace even more fossil fuel generation, especially old coal-fired facilities. (See final section of this chapter.)

WIND TURBINE TECHNOLOGY

The size of commercially available wind turbines has been increasing steadily over the past two decades, enabling better economies of scale and energy conversion efficiency, Table 3.11 illustrates these changes.

TABLE 3.11: *Wind Turbine Size Changes*

Year	Average Rating (kW)
1980	150-400
1990	600-750
2000	1000-1600

Larger and taller wind turbines result in increased power output. The current generation has a 50m hub height and is 20-25% efficient, 98% Available with 25% Power Losses. Advanced turbine designs are 100m tall, 30-35% efficient, 99% Available with 10% power losses. Ongoing research into two- and three-blade systems, will continue to push performance higher and costs lower.

China is currently the world's largest manufacturer of small wind turbines, and now has a total of 36 MW of grid-connected capacity. China is targeting 250-550 kW wind turbines for domestic production and is working with technology partners to reach, perhaps even exceed, that goal. If these plans come into fruition, capital costs may fall as low as $500 / kW.

ESS modeling assumes 750 kW turbines for on-shore applications and 1.5 MW for offshore units. The wind resource near the coast is calculated to be an average of class 3 at 50-meter hub height, which yields a capacity factor of 25% for on-shore turbines. The offshore installations are assumed to run at 37.5% capacity factor because of the better quality and more frequent wind available at sea.

WINDPOWER ECONOMICS

The use of windpower is determined by the wind resource, topography and economics. To be competitive, windpower must be comparable on a cost basis to fossil technologies, often gas turbine combined cycle units, which can produce power for around 4 cents / kWh, depending on fuel costs. Table 3.12 displays three cases for windpower (in the United States) and how it compares to fossil competitors. Note that this analysis does not take into consideration any environmental benefits of wind versus fossil. If costs continue to fall, windpower may quickly gain market share in wind-resource rich areas, even without government subsidies and tax advantages.

For Shandong, we model two wind scenarios, one with 101 MW / year of land-based turbines from 2005 through 2019, and the second adding 200 MW / year of offshore turbines from 2010 through 2019. The technology chosen is an advanced three-blade upwind turbine. The land-based units have an availability of 25% and are each 750 kW in size. The offshore units are modeled with 35% availability and 1.5 MW in size. Fixed O&M expenses are assumed to be $15 / kW-yr for offshore units and 10 $ / kW-yr for on-shore, while variable O&M is set at 5 $ / MWh for both types of units (see Table 3.12).

TABLE 3.12: *Parametric Evaluation of Wind Electricity Costs*

(McGowan and Connors, 2000)

PARAMETER	UNIT	BEST	MID-RANGE	WORST
Capacity Factor	(%)	40	25	20
Overnight Cost	($/kW)	750	1000	1500
Fixed O&M	($/kW-yr)	10	15	30
Variable O&M	($/MWh)	2	8	12
Cost of Electricity	(¢/kWh)	2.63	6.05	11.47

SOLAR AND HYDRO FOR POWER GENERATION IN SHANDONG

The use of solar photovoltaics and solar thermal conversion technology was evaluated for Shandong province and found to be too expensive for large-scale power production, which is not to say that solar technology will not be used in niche applications in the province. However, with capital costs alone in excess of $3000/kW, solar technology will be relegated to experimental and small applications. Table 3.13 displays the relative costs of solar.

Hydroelectric power was also considered, but the lack of available sites for dam and turbine construction leaves only small-scale options for Shandong. The quantity of power would not be meaningful on a province model level.

TECHNOLOGY ECONOMICS AND DEPLOYMENT

Table 3.13 displays the cost and performance assumptions for alternative electricity generating technology used in the ESS modeling. Capital costs represent more than 80% of the per unit energy costs for waste-to-energy technologies, since fuel is obtained at no cost and operations and maintenance costs are relatively low.

TABLE 3.13: *Technology Economic and Performance Assumptions*

Technology	Fuel	Unit Size	Overnight Cost	Fixed O&M	Var. O&M	Thermal Eff. (LHV)	
Photovoltaics	Sun	1.00	3500	5	0.0		
"	Sun	5.00	3000	5	0.0		
Solar Thermal	Sun	100.00	2000	30	0.0		
MSW Boiler	MSW	30.00	2000	100	10.0	23	15651
Spark Ignition Engines	Std. LFG	1.00	800	40	0.5	27	13332
"	Bioreac. LFG	1.00	960	60	0.5	30	11999
"	CBM	1.00	500	60	0.5	30	11999
Wind (onshore)	Wind	0.75	650	15	5.0		
Wind (offshore)	Wind	1.50	800	20	5.0		
Generic Biomass	Wood/Agr.	50.00	1200	40	3.0	22	16362
		(MW)	($/kW)	($/kW-yr)	($/MWh)	(%)	(kJ/kWh)

Of the large-scale facilities examined for dealing with MSW, mass burn units most efficiently convert urban waste into electricity. However, the waste must be high in combustibles (plastics and paper) to utilize this technology. Bioreactors are twice as efficient as normal landfill gas installations at converting food and yard waste into electricity. Overall, anaerobic digesters are the most efficient waste-to-energy technology, but they are limited by both fuel and size. They have achieved widespread use (over 6 million units) in rural China, India, and Latin America to produce heat, cooking fuel and some limited power for small villages and city suburbs.

TABLE 3.14: *ESS Scenario Assumptions for the Deployment of Wind and Landfill Gas Generation in Shandong Province*

	Windpower		Bioreactor
Year	Onshore	Offshore	SI Engines
2001	0.0	0.0	
2002	0.0	0.0	26.0
2003	0.0	0.0	18.0
2004	0.0	0.0	19.0
2005	100.5	0.0	17.0
2006	100.5	0.0	8.0
2007	100.5	0.0	10.0
2008	100.5	0.0	10.0
2009	100.5	0.0	11.0
2010	100.5	300.0	13.0
2011	100.5	300.0	14.0
2012	100.5	300.0	14.0
2013	100.5	300.0	16.0
2014	100.5	300.0	18.0
2015	100.5	300.0	19.0
2016	100.5	300.0	19.0
2017	100.5	300.0	18.0
2018	100.5	300.0	17.0
2019	100.5	300.0	15.0
2020	0.0	0.0	14.0
2021	0.0	0.0	16.0
2022	0.0	0.0	16.0
2023	0.0	0.0	17.0
2024	0.0	0.0	17.0
Total	1507.5	3000.0	362.0

(MWs)

For the ESS scenarios, due to the applicability of the technologies described, and the anticipated size of the "fuel" resource, only windpower and bioreactor landfill gas options were modeled. Table 3.14 details the installation schedule used in ESS modeling; note that each wind site may be disaggregated physically, but the MW installed figure represents the total capacity that is grid-connected in a given year regardless of location. The same is true for spark engines, which come in one MW sizes and can be moved from site to site depending on gas production levels. In the ESS scenarios, windpower deployment is halted after 2019 so that the longer term impacts of the onshore and offshore wind resources can be evaluated.

Prepared by Christopher Hansen with the assistance of Stephen Connors and Chia-Chin Cheng

CHAPTER 4: SULFUR CONTROLS ON EXISTING AND NEW GENERATION

INTRODUCTION

Electricity production from coal has many environmental liabilities, and the 97% of power produced form coal in Shandong Province, China is no exception. Existing coal-fired generation units are large emitters of sulfur oxides (SO_X) and other pollutants. These older, and generally smaller units often have relatively high emissions since they lack emissions control equipment and have lower overall generation efficiencies. Therefore, one option that must be considered in evaluating cost-effective air quality improvement is retrofitting existing generators with sulfur controls. Likewise, new generation units can employ different types of sulfur controls, with different levels of cost and emissions reduction.

An understanding of sulfur control regulations in China is necessary to accurately model the costs and emissions reduction potential of both retrofitting existing generation and installing control technologies on new units. This document reviews current sulfur regulations, the general characteristics of sulfur removal technologies and presents the assumptions used for modeling sulfur control options in the Electric Sector Simulation task.

REGULATORY BACKGROUND

In January of 1998 the STATE COUNCIL approved plans put forth by the STATE ENVIRONMENTAL PROTECTION ADMINISTRATION (SEPA) for the reduction of sulfur emissions from existing and new power plants. These plans call for all existing units using coal with greater-than-1% sulfur content to take measures to reduce SO_X emissions by 2000, and to install proper sulfur control equipment by 2020. Similarly, they call for all new and revamped units using coal containing greater-than-1% sulfur to have proper sulfur control equipment installed by 2000. The plan also sets total emission control targets, but without detailing specific emissions reduction standards. (Wang, 1999)

CANDIDATE FLUE GAS DESULFURIZATION TECHNOLOGIES

Our analysis considers four commercially available FGD technologies: Wet Scrubber (WS), Sea Water Scrubber (SW), Spray Dry (SD), and the Furnace Sorbent Injection/LIFAC method (LIFAC), which are described in Table 4.1. As the sulfur removal efficiency of each FGD technology type varies with coal quality, the Ca/S molar ratio, furnace design and boiler size, we categorized FGD performance into high (circa 90% sulfur content removal), medium (circa 80%) and low (circa 65%). Table 4.2 presents the basic characteristics of each of the technologies.

TABLE 4.1: *Brief Description of Flue Gas Desulfurization (FGD) Technologies*

WET SCRUBBER (WS)

Since it was developed in 1970s, wet scrubber technology has become the most prevalent, as it is used in 85% of generating units employing sulfur controls worldwide (Zhang, 1999). This technology uses a sorbent to absorb SO_2 through a nearly stoichiometric (1:1 Ca:S ratio) process in absorption towers or vessels. The solvent generally consists of a wet mixture of lime, limestone, sodium based reagents, ammonia, and dual alkali (Fukusawa, 1997). The final product (gypsum) can be retrieved from the unit's wastewater and sold. Wet scrubbers technology is generally characterized as a high cost, highly efficient and low down time technology.

SEA WATER SCRUBBER (SW)

This is a low cost, easily maintained FGD technology appropriate for coastal power plants burning lower-sulfur coal. About 20 SW FGD units have been installed worldwide, including one in a 300 MWe unit at China's Shanjun West Plant in Guandong Province. This technology directs sea water into an absorption tower as a sorbent, which is then discharged back to the sea with little pollution and no limestone use.

SPRAY DRY (SD)

The Spray Dry method is a mature technology with a diffusion rate of 8.4% worldwide (Zhang, 1999). This process sprays a semi-dry lime solution in fine droplets into a vessel which dries while reacting with flue gas SO_2. The incorporation of pre-scrubber fly ash collection, which is common in Europe, makes the by-product of this method usable (Fukusawa, 1997). SD performance can vary depending on the Ca/S ratio used, though removal efficiencies of 90% can be achieved with higher than stoichiometric (30-40%) use of lime (1.4 to 1 Ca:S ratio).

FURNACE SORBENT INJECTION / LIMESTONE INJECTION INTO THE FURNACE AND ACTIVATION ON CALCIUM OXIDE (LIFAC)

Furnace Sorbent Injection (FSI) Technology has been revisited in recent years since its development in the late 70s. The newly modified technology injects pulverized limestone into the upper part of a boiler near the superheater. A humidification (activation) reactor achieves further SO_2 absorption downstream. The LIFAC method utilizing an appropriate Ca/S ratio can remove 75-80% of SO_2 used (US DOE, 1998).

TABLE 4.2: *Characteristics of FGD Technologies*

Technology	Sorbent	Sulfur Removal Efficiency		Cost	Space Required
		Low S Coal	High S Coal		
WS	Lime / Limestone	High	High	High	Large
SW	Sea Water	High	High	Low	Large
SD	Lime	Medium	Medium to Low	Medium	Large
LIFAC	Lime / Limestone	Medium	Low	Low	Small

Tables 4.3 and 4.4 present the applicability of the above FGD technologies in our simulation based on unit type (existing or new), size and location (inland or coastal). We ascribed a code name for each technology in each setting, which we also in turn associated with costs and performance characteristics.

TABLE 4.3: *Technology Options for Retrofitting Existing Units*

Location:	**Inland**			**Coastal**
FGD Performance:	High	Medium	Low	
Unit Size				
Large (≥300 MW):	WS1	SD1	SD2	SW1
Medium (100-250 MW):	WS2	LIFAC1	LIFAC3	SW2
Small (50MW):		LIFAC2	LIFAC4	SW3

(FGD Technology Code)

TABLE 4.4: *Technology Options for New Generation Units*

Location:	**Inland**			**Coastal**
FGD Performance:	High	Medium	Low	
Unit Size				
Large (≥300 MW):	WS3	SD5	SD6	SW4
Medium (100-250 MW):	WS4	LIFAC7	LIFAC8	SW5

(FGD Technology Code)

DETERMINING COSTS

The power market in China is sensitive to cost because electricity is such an important factor in driving economic growth. Low factors of production have helped to spur the rapid economic expansion in Shandong, thus our analysis considers three primary types of costs: capital costs, fixed operation and maintenance (O&M) costs, and variable O&M costs. Other potential direct and indirect costs include fees for emitting sulfur to the atmosphere and fuel consumption impacts due to decreased overall unit efficiency (i.e. increased auxiliary power consumption). For example, wet scrubber and spray dry *retrofitted* units take a 1% point reduction in efficiency as well as a 1% drop in plant output, such that a 300 MW nameplate capacity pulverized coal plant that is 33% efficient, is modeled as a 297 MW, 32% efficient unit after the FGD retrofit. We assume that sea water retrofits, which need less electricity to operate, cause only a 0.5% percentage point reduction in efficiency and do not derate the capacity.

Capital Costs. Due to economies of scale, increasing unit size can significantly diminish the capital costs of various FGD technologies. Taking this into account, we used a curve fitting technique for retrofitting existing U.S. coal-fired generation with wet scrubbers. We then used this curve to extrapolate capital costs for 50, 200 and 300 MW units in China, using various multipliers to reflect Chinese capital costs, and applied it to all the FGD technologies used in the study. For new units, we further assumed a 20% discount on all capital costs for FGD installation to account for cost-savings in overall plant design, equipment requirements and ease of construction by integrating the sulfur control technology into the design instead retrofitting. Tables 4.5 and 4.6 list the capital costs of installing FGD in existing and new units in Shandong. Figure 4.1 demonstrates the economy of scale benefits derived.

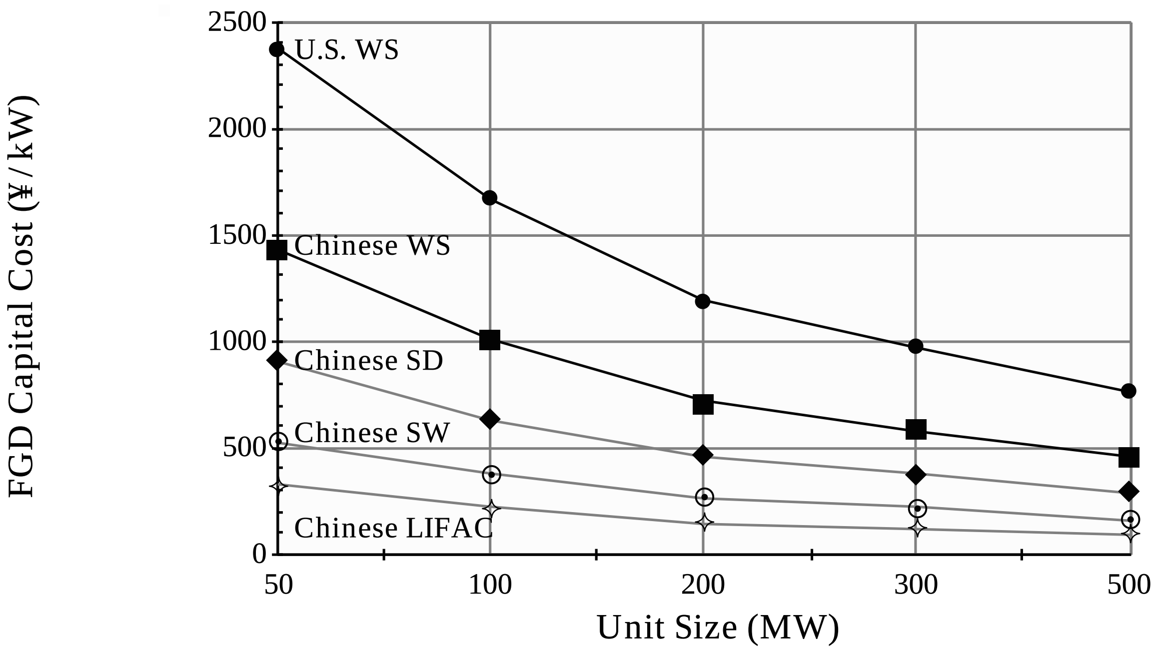
TABLE 4.5: *Capital Costs for Retrofitting Existing Chinese Generation Units with Sulfur Removal Technologies*

	Technology Cost Multiplier	Unit Size (MW) 50	200	≥300
Baseline U.S. WS	1.00	2374	1188	970
Chinese WS	0.60	1425	713	582
Chinese SD	0.38	902	451	368
Chinese SW	0.22	522	261	213
Chinese LIFAC	0.13	309	154	126
			(¥/kW)	

TABLE 4.6: *Capital Cost of Sulfur Removal Technologies for New Chinese Generation Units*

	Technology Cost Multiplier	Unit Size (MW) 50	200	≥300
Baseline U.S. WS	1.00	2374	1188	970
Chinese WS	0.6*0.8	1140	570	465
Chinese SD	0.38*0.8	722	361	295
Chinese SW	0.22*0.8	418	209	171
Chinese LIFAC	0.13*0.8	247	124	101
			(¥/kW)	

FIGURE 4.1: *Economies of Scale for FGD Retrofits*



Operation and Maintenance Costs. We expressed variable O&M costs in a Yuan (¥) per kWh, and assume that variable O&M costs are only affected by coal quality, because using per-kWh units normalizes the capacity effect. Lower quality coal (with sulfur content higher than 1.6 %) requires 1.2 times higher O&M costs because more material, manpower, resources and energy are required to remove the additional SO_X it generates. Table 4.7 lists our cost assumptions for all FGD technologies.

TABLE 4.7: *FGD Cost and Performance Assumptions*

	Unit Capacity	Sulfur Content	SO_2 Removal Efficiency	Capital Cost	Fixed O&M	Variable O&M
FGD Retrofits						
WS1	≥300	any	90	582	16.0	0.009
WS2	200	any	90	713	17.6	0.009
SD1	≥300	0.1-1.5	80	368	12.0	0.010
SD2	≥300	1.6 +	65	368	12.0	0.012
LIFAC1	200	0.1-1.5	80	154	*	0.013
LIFAC2	50	0.1-1.5	80	309	*	0.013
LIFAC3	200	1.6 +	65	154	*	0.015
LIFAC4	50	1.6 +	65	309	*	0.015
SW1	≥300	any	90	213	12.0	0.003
SW2	200	any	90	261	12.0	0.003
SW3	50	any	90	522	12.0	0.003
FGD on New Generation						
WS3	≥300	any	90	524	16.0	0.009
WS4	200	any	90	641	17.6	0.009
SD3	≥300	0.1-1.5	80	332	12.0	0.010
SD4	≥300	1.6 +	65	332	12.0	0.012
LIFAC5	200	0.1-1.5	80	139	*	0.013
LIFAC6	200	1.6 +	65	139	*	0.015
SW4	≥300	any	90	192	16.0	0.003
SW5	200	any	90	235	16.0	0.003
	(MW)	(%S)	(S)	(¥/kW)	(¥/kW-yr)	(¥/kWh)

* No assumptions for Fixed O&M were made

MODELING APPROACH

ESS aims to model the impacts of a Chinese regulatory environment in which further SO_X reductions may be imposed in the future. And, as described above, we allow for implementation of various FGD technologies to meet our stakeholders' environmental performances and cost-effectiveness goals.

MODELING ASSUMPTIONS

Our SO_X control options apply to both new and existing generation units. Though for planning purposes we considered all units (including those using coal with less-than-1% sulfur content) as potential candidates for further sulfur control. China is currently targeting three types of units in this effort. We represent these categories as ≥300 MWe, 200 MWe, and 50 MWe units respectively in the scenario set (See Table 4.7). China plans to retire most units with a capacity of 50 MWe or less by the end of 2003, thus they are not candidates for retrofitting. In addition, we do not model LIFAC as a retrofit option because it is best suited for small plants and the efficiency is lower.

The data we used to develop our cost assumptions comes from various sources. Whenever available we used Chinese field data, and also made estimates specifically for Chinese units based on data applicable elsewhere. For example, the cost and performance data of the FGD technologies that serve as a knowledge base for this component of our analysis are shown in Appendix B. These data may or may not provide sufficient detail for all applications, such as unit size, operating condition, coal quality and source, currency used, data year, etc. To normalize our data, we made the following assumptions.

- All units operate 5500 hours per year, or a capacity factor of 62.8%.
- The Chinese exchange rate is fixed to 8 Yuan RMB per dollar.
- Inflation effects are not considered.

CONCLUSION

Sulfur control on old and new units is a top priority for the Chinese government because of the environmental and human health effects of SO_x. ESS analysis allows for a robust comparison of many different types of control technologies on a cost and performance basis. Reductions in sulfur depend on a three pronged approach, using lower sulfur coal, preparing the coal before combustion and removing sulfur after combustion before it is released in to the atmosphere. Removal does have a cost impact on coal units, but will help to improve the environment and reduce sulfuric acid damage.

Prepared by Chia-Chin Cheng with the assistance of Stephen Connors, Christopher Hansen and Jennifer Barker

CHAPTER 5: PARTICULATE MATTER CONTROLS ON EXISTING AND NEW GENERATION

INTRODUCTION

In China, many cities and their inhabitants suffer from serious particulate pollution attributable in part to power generation. Particulates' adverse health impacts include respiratory disease, allergic reactions and potential carcinogenicity. Fine particulates can also impair visibility by scattering light. Thus, particulate matter (PM) control is an important component of power plant emissions control.

Chinese environmental regulations currently require all new power plants to install electrostatic precipitators with over 99% PM removal efficiency (PNNL, 1998). However, some old power plants are still using venturi, water film and other less efficient particulate control devices, or have no PM control measures installed (Wang, 1999). In this document, we discuss the technological options available in Shandong for PM control in old generation units, as well as options available for PM control in new units.

CLASSIFICATION OF PARTICULATE MATTER EMISSIONS FROM POWER PLANTS

PM is not a single pollutant, but is rather a mixture of many chemical species. These chemicals differ in their formation mechanisms, chemical compositions, and size ranges, which can result in different exposure patterns and health effects.

1. *PM Categorization By Source and Formation Mechanism*

PM emissions from power plants come from two major sources: combustion and coal preparation/handling. The first source of PM emissions are from the combustion process, which includes the ash from fuel combustion and unburned carbon left over from incomplete combustion. Secondary PM, formed from the reaction and condensation of precursor gases from the flue gas also contributes to PM emissions in this category.

The second source of PM emissions is so-called fugitive emissions stemming from the coal preparation and ash handling processes. Coal crushing, pulverizing, loading and unloading, and the handling of bottom ash and collected fly ash from particulate control units are the major sources of fugitive PM emissions.

2. *PM Categorization By Chemical Composition*

The composition of PM emissions from coal-fired boilers is a complex function of boiler configuration, boiler operation, coal properties and pollution control equipment (USEPA, 1998). The main group of PM emissions is primarily composed of inorganic residue (fly ash) from combusted coal, and occurs particularly in pulverized units where combustion is nearly complete.

The second group of PM pollutants comes from the condensation of unburned semi-volatile organic and/or inorganic compounds (PESI, 1999). The condensable

PM emitted from coal or oil-fired boilers is primarily inorganic in nature (USEPA, 1998). The size of these so-called condensable or unfilterable particulates is generally small (less than 0.3 microns) making them able to pass through particulate control devices. Though the term "condensable PM" is thus defined, it is often understood to be inclusive of secondary PM as well, which is described below.

The third group of particulates is derived from heterogeneous chemical reactions and are usually called secondary PM. Gases such as NO_X, SO_X and some organic gases are converted into very fine nuclei in the atmosphere and condense onto existing particles, which then coagulate into small particle forms (EPA, 1999). Since secondary PM forms beyond the stack, it must be controlled through precursor gases mitigation. Control of sulfur dioxides is described in the chapter "Sulfur Controls on Existing and New Generation."

3. *PM Categorization By Particle Size*

PM occurs in different sizes depending on how it is formed, as depicted in Table 5.1. As the table also shows, PM emissions are classified for regulatory purposes into two size categories by the U.S. Environmental Protection Agency.

TABLE 5.1: *Size Distribution of Particulate Matter*

Size by Formation		Size by Regulation	
Particlate Mode	MMAD (mm)	Particlate Type	MMAD (mm)
Coarse	6 - 20		
		PM-10	< 10
Fine	< 3	PM-2.5	< 2.5
Accumulated	0.3 - 0.7		
Droplet	0.5 - 0.8		
Condensation	0.2 - 0.3		
Nuclei	0.05 - 0.07		

Source: USEPA, 1999 Note: MMAD = mass median aerodynamic diameter

Coarse mode PM is typically generated from pre-combustion treatment or combustion processes involving larger-sized particles, whereas fine PM is generally formed from the by-products of combustion. Condensable and secondary PM both fall near the lower bound of the fine particulates scale with sizes ranging down to 0.05 µm. However, these groups do overlap with primary fine particulates, which range in size from 1 to 3 µm.

Smaller PM can cause more serious human health effects as they are capable of deposition in the lower region of the respiratory tract. They are also more effective at scattering and absorbing light, and are thus the primary cause of reduced visibility. Regulatory efforts in the United States have been increasingly focused on the control on small PM. For example, US NAAQS (National Ambient Air Quality Standard) established a threshold of 10 µm for small-size particulates in 1987 (EPA Website, 1996), though this choice was partially driven by limitations of monitoring devices. In 1997, the US promulgated a 2.5 µm standard for more precise regulation of fine PM. In China, though ambient PM standards have not yet been established, PM control equipment is required for all new power generation units and performance standards are being enforced.

PARTICULATE MATTER CONTROL

Modern particulate control technologies include cyclone (multicyclone), wet scrubber, fabric filter (baghouse) and electrostatic precipitator (ESP) systems as shown in Table 5.2. We adopt the efficiency and cost information presented here as baseline assumptions for our modeling. Note that depending on boiler type, particle size distribution and operating conditions each technology's removal efficiencies for different ranges of particles can vary.

TABLE 5.2: *Comparison of PM Control Technologies*

Particulate Removal Technology	Removal Efficiency [1]	Capital Cost	Additional O&M	Installation 1997 [2]
Wet Scrubber	90.0			20%
Cyclone (s)	80.0			10%
ESP (estimated) [3]	99.0	240 - 720	0.24	70%
ESP (Changchun Case) [4]	99.6	141		
Baghouse (estimated) [3]	99.9	320 - 480	0.24	
	(% Removal)	(Yuan/kW)	(¢/kWh)	(% in China)

Sources: [1] EPA, AP-42, Chap. 1, Sup. B, 1![3] PNNL, 1998
[2] Wang, JX, 1999 [4] He, WB, 1999

Wet Particulate Scrubbers

Wet scrubbers, commonly used in China in the past, remove flue gas particulates at high percentages (90%+). Wet scrubber types include venturi, flooded disc scrubbers and turbulent contact absorbers, etc. (USEPA, 1998). Wet scrubbers' overall PM collection efficiency is 90 percent or greater (USEPA, 1996), and their removal efficiency for 2-micron particles can reach 95 to 99 percent (USEPA, 1998).

Cyclones

Cyclones are mechanical separation devices that use centrifugal force to remove particulates and can be installed upstream of other PM control devices to reduce overall cost. However, they are relatively ineffective for collection of particles less than 10 microns in diameter (USEPA, 1998). Cyclones' overall collection efficiency is typically around 80 percent (USEPA, 1996).

Electrostatic Precipitator

ESPs are widely used in China in new generation units as well as in retrofits of old units. ESP is popular because it can be applied to a wide range of system sizes and has little adverse effect on combustion performance (USEPA, 1998). ESPs' fractional collection efficiencies are greater than 99 percent for fine (less than 0.1 microns) and coarse particles (greater than 10 microns). However, data for coal-fired sources shows a reduction in ESP collection efficiencies for particle diameters between 0.1 and 10 micrometers (USEPA, 1998). When applied to low sulfur anthracite units, the efficiency of ESP is only 90 to 97 percent (USEPA, 1998). The cost of ESPs can also vary widely depending on the required removal efficiency. An ESP retrofit case in Changchun in 1997 reports capital costs around 150 ¥/KW, though Pacific Northwest National Laboratories (PNNL) reports them to vary in the range of 240-720 ¥/KW.

Baghouse

Fabric filtration has been widely applied to coal combustion sources since the early 1970s. It consists of a number of filtering bags along with a cleaning system to trap PM in the flue gas, and has a removal efficiency of 99+ percent. However, the use of baghouses does cause higher pressure losses than the ESP, which reduces overall plant efficiency. Pacific Northwest National Laboratory (PNNL) capital cost estimates for baghouse filters are in the 320 to 480 ¥/KW range (PNNL, 1998).

MODEL INPUTS

Among the PM removal technologies available, we chose to model retrofitted and new ESP and baghouse systems in Shandong for economic and environmental performance. Cost estimates for PM control technologies varies significantly across reference sources. As the Changchun case was a real expenditure to retrofit a Chinese unit with ESP, we give it more weight in considering the capital cost of installing ESP. After adjusting for inflation to the base year of our study (1999) and considering cost variations, we chose 200 ¥/kW as the capital cost for ESP retrofits and 160 ¥/kW for new ESP systems. We discount capital costs for new units by 20% from retrofitting costs to reflect lower costs of installation during original construction (see Table 5.3). In the modeled ESP systems, we reduce the removal efficiency because of the high ash content of Chinese coal and onerous O&M requirements. New unit ESPs are assumed to have only 95% removal efficiencies with raw coal and 97% efficient with prepared coal. Prepared coal has on average 40% less ash content than raw coal in Shandong. We set all additional O&M costs for PM technologies to 0.24 ¥/kWh.

For better control of PM, especially PM-10 and PM 2.5, baghouses may be necessary to meet more stringent regulations in the future. We use capital costs of 300 ¥/KW for retrofitting and 240 ¥/KW for new units.

TABLE 5.3: *Model Inputs for PM Control Technologies in ESS Study*

Particulate Removal Technology	Coal Type	Removal Efficiency	Capital Cost	Additional O&M
ESP (Modeled)				
New	Raw	95.0	160	0.24
Retrofit	Raw	95.0	200	0.24
New	Prepared	97.0	160	0.24
Retrofit	Prepared	97.0	200	0.24
Baghouse (Modeled)				
New	Raw	99.9	240	0.24
Retrofit	Raw	99.9	300	0.24
		(% Removal)	(¥/kW)	(¥/kWh)

CONCLUSION

Particulate control is an immediate concern for Chinese officials. The addition of particulate controls on coal power plants can have a pronounced effect on particulate levels. The use of ESP's on old units and the requirement that all new units have sufficient PM controls should help Shandong and China reach the goal of lower PM levels.

Prepared by Chia-Chin Cheng with the assistance of Stephen Connors, Christopher Hansen and Jennifer Barker

CHAPTER 6: CLASSIFICATION OF STEAM COAL FOR ELECTRIC SECTOR SIMULATION SCENARIOS

INTRODUCTION

The properties of fuels directly impact the thermal and environmental performance of generation units. As coal is responsible for over 95% of electricity generation in Shandong, its combustion properties are of particular interest when looking at opportunities to improve system performance and reduce pollutant emissions. Therefore, describing the characteristics of coal used in generation units is an essential element of the Electric Sector Simulation (ESS) task. Due to the complex chemical composition and impure nature of coal, the different classification systems used in different countries, and relatively limited information on the basic properties of Chinese coal, it has been necessary to construct a robust set of modeling assumptions for the quality of coal used in Shandong. This document describes these assumptions and their development.

We developed the coal classification system presented here using information provided by the Shandong Electric Power Research Institute (SEPRI), supplemented with information from Chinese and American Coal bureaus and other published sources. This document describes how we developed this classification system for several types of raw "as mined" steam coals, and for prepared coal. The following chapter "Coal Cost Assumptions and Coal Cost Uncertainty Development" describes how we developed our uncertainties for future coal costs.

WHAT IS COAL?

Coal is an organic rock derived from ancient plant debris. The chemical and physical properties of coal depend mainly on the plant material and associated inorganic matter from which the coal originated, and the conditions that prevailed during this original material's transformation into rock. (Speight, 1994) As such, the composition of coal can vary considerably from region to region and from seam to seam within a single mine. Apart from the base organic matter, coal also includes a considerable amount of mineral, water and gaseous materials. These impurities also affect the combustion properties of coal.

There are two conventional methods of describing coal's physical make-up: Proximate Analysis and Ultimate Analysis.

- Proximate Analysis determines the general properties of coal. It involves the determination of moisture, volatile matter, ash and fixed carbon content.
- Ultimate Analysis involves a further elemental decomposition of moisture-free coal. This process determines the proportion of carbon, oxygen, hydrogen, nitrogen, sulfur, and ash in percentage terms. (Speight, 1994)

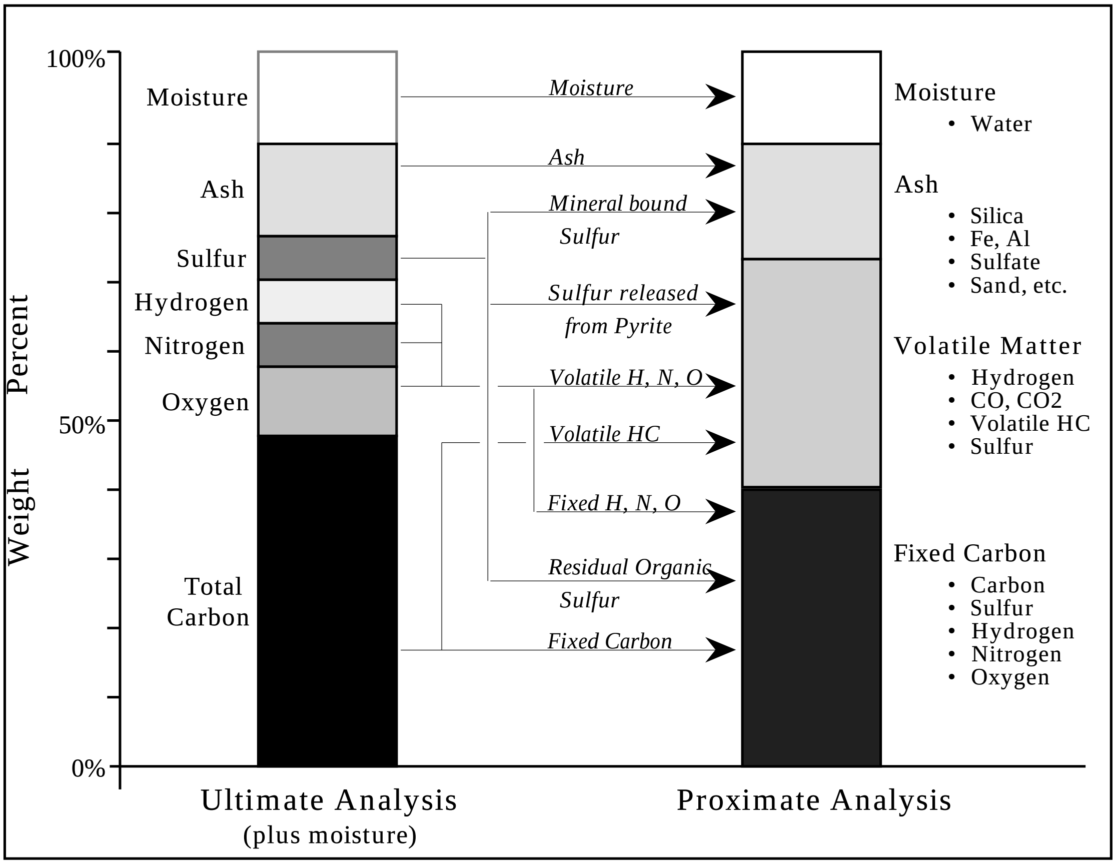
TABLE 6.1: *Proximate Analysis Components of Coal*

FIXED CARBON is determined by subtracting from 100 the sum combined weight percent of moisture, volatile matter, and ash (Speight, 1994). Fixed carbon is the solid combustible matter in coal after the expulsion of volatile matter. Fixed carbon contains principally carbon, but also small amounts of sulfur, hydrogen, oxygen, and nitrogen. (EIA, 1995)
VOLATILE MATTER data are obtained by heating dry coal samples in a covered crucible to a temperature of 950°C. The lost weight in coal expressed in weight percent is the volatile matter content. The volatile matter contains mainly combustible gases such as hydrogen, carbon monoxide, methane and other hydrocarbons. Tar and incombustible gases such as carbon dioxide and structural water are produced. (Speight, 1994) Volatile matter and fixed carbon are both components of coal's total heat content. Volatile matter influences the ignitability and overall combustion of a coal and contributes about 25 to 40 percent of the thermal energy, with fixed carbon contributing the remaining 60 to 75 percent. (EIA, 1995)
ASH is a residue derived from the mineral matter content of coal during complete combustion. It differs from the mineral matter originally present in the coal (e.g. as a constituent of fixed carbon). Ash reduces the net heat generation per unit weight of coal, decreases energy per unit weight (per tonne), and increases fuel costs on an energy basis. Ash content is an important property both in both coal preparation and combustion. Flyash refers to the ash contained in the flue gases, while bottom ash refers to the solid residue of coal combustion. Different coal combustion approaches, including boiler configurations can result in different contributions to flyash and bottom ash, as well as ash deposits on boiler walls and boiler tubes. Ash contributes to the solid waste stream of a power plant, either as bottom ash or flyash collected by particulate removal systems. Such ash requires proper disposal, although flyash is commonly used as ingredient in concrete. Overall, reduction of ash through coal preparation prior to combustion is desirable for the operation of power plants. The amount of ash is usually determined by burning a sample in an adequately ventilated furnace at the temperature range of 700 to 750 °C. (Speight, 1994)
SULFUR exists in coal either as organically bound sulfur or as inorganic sulfur forms (pyrite, marcacite and sulfates). These sulfur forms can change their chemical compositions during combustion and in the analytical processes, which complicates the determination of sulfur composition. For example, organic sulfur can be fixed as sulfate (inorganic) and appears in ash. However, sometimes, Iron Pyrite (FeS) can lose its sulfur to volatile matter during chemical analysis (see Figure 6.1).
MOISTURE in coal affects the generation of heat (net) during combustion. The total moisture in coal includes surface, inherent, and structural moisture. Inherent moisture is what is held within the pore structure of coal and should be measured after air-dried so that surface moisture is taken out. (Speight, 1990) To determine inherent moisture, a coal sample is only heated to 105 to 110°C. At this temperature, the water molecules present in the structure of clays and other minerals would not be released. (Speight, 1990) Therefore, a coal's moisture content *does not* include structural water.

Figure 6.1 shows the relationship between Proximate and Ultimate analysis. Note that while the "Total Carbon" category in Ultimate Analysis includes virtually all occurring elemental carbon, the "Fixed Carbon" category in Proximate Analysis includes carbon fixed in combination with several other elements. Moreover, Proximate Analysis represents a portion of the carbon present in the "Volatile Matter" category. Thus, due to the different ways these techniques represent carbon content, the "Total Carbon" category of Ultimate Analysis is the most reliable source for calculating CO_2 emissions. It is also important to note that the "Sulfur" category in Ultimate (elemental) Analysis is comprised of both organic sulfur and "mineral" sulfur (mostly Iron Pyrite – FeS). Mineral sulfur tends to occur in coal ash, whereas

organic sulfur occurs in both volatile matter and fixed carbon. Thus for coals high in mineral sulfur, removal of ash and particulates can reduce sulfur emissions as well.

FIGURE 6.1: *Relationship between Proximate and Ultimate (with moisture) Analysis for Coal Chemical Composition*



The forms of sulfur present in coal determine whether the sulfur can be taken out of coal through the coal preparation process. Inorganic sulfur can be washed out with ash, while organic sulfur that is chemically bound with carbon (as a constituent of fixed carbon) is not commonly removed. The proportion of organic and inorganic sulfur varies greatly. In China, according to Speight (1994) Taitung coal contains approximately 30% organic sulfur and 70% inorganic sulfur. SEPRI data shows about 30-40% of the sulfur in Shandong generation coal is inorganic, the rest 60 to 70% exist in the organic form.

Among the elements in ultimate analysis, sulfur and carbon content are a good indication of the pollution generating potential of coal. Nitrogen in coal, along with atmospheric nitrogen contributes to NO_x emissions. Of these chemically reactive pollutants, only sulfur can be reduced from coal via preparation, which greatly improves the environmental performance of coal combustion.

Due to the complexity of coal, different temperature and time settings can greatly affect the result of coal quality analyses. It is therefore necessary to set standardized procedures in order to get comparable results. However, different standards use different procedures/conditions to determine the proximate and ultimate properties of coal. We relied on ASTM (American Society for Testing Materials) standards (ASTM D3172 for proximate analysis and ASTM D3176 for ultimate analysis) in the description of coal in CETP ESS study. Other analytical methods such as free swelling testing, Toga testing and Gray-King testing determine the physical properties of coal, which are more pertinent to coking processes. Other classification methods such as UK Coal Survey System and the International System specifically treat the coking properties of coal. The China National Standard for Coal Classification is itself based on analyzing coal's coking properties, and makes use of the free swelling and caking indices.

TYPES OF STEAM COAL

For the electric sector simulation task we are predominantly interested in the properties of "steam coal" for power generation, as opposed to coal used as a feedstock in materials industries (e.g. coking). The most common classification system for steam coal is that of the American Society of Testing Materials (ASTM). Based primarily on the proximate analysis of coal, ASTM classifications range from anthracite to lignite according to a coal's lower heating value absent moisture (LHV, GJnet) and fixed carbon content. Table 6.2 gives the heating values and proximate analyses of ASTM standard coals. Figures 6.2 and 6.3 present this information graphically. Table 6.3 and Figure 6.4 show the ultimate analysis for these coals, with moisture added back in. (EIA, 1995)

TABLE 6.2: *Heat Content and Proximate Analysis of ASTM Coals*

	Heating Value			Proximate Quality			
Coal Type	LHV	HHV	Δ HV	Moisture	Vol.M.	Fixed C	Ash
Meta-Anthracite	21.7	25.0	3.3	13.2	2.6	65.3	18.9
Anthracite	30.0	31.4	1.4	4.3	5.1	81.0	9.6
Semianthracite	32.3	33.1	0.8	2.6	10.6	79.3	7.5
Low-Volatile Bituminous	33.5	34.5	1.0	2.9	17.7	74.0	5.4
Med-Volatile Bituminous	33.3	34.0	0.7	2.1	24.4	67.4	6.1
High-Volatile A Bituminous	32.7	33.5	0.8	2.3	36.5	56.0	5.2
High-Volatile B Bituminous	27.2	29.7	2.5	8.5	36.4	44.3	10.8
High-Volatile C Bituminous	25.2	29.4	4.2	14.4	35.4	40.6	9.6
Sub-Bituminous A	24.8	29.8	5.0	16.9	34.8	44.7	3.6
Sub-Bituminous B	22.4	28.7	6.4	22.2	33.2	40.3	4.3
Sub-Bituminous C	20.1	27.4	7.3	26.6	33.2	34.4	5.8
Lignite	16.3	25.8	9.5	36.8	27.8	29.5	5.9
t = tonne	(GJnet/t)	(GJgr/t)	(ΔGJ/t)	(weight %)			

(Source: IEA, DOE 1995)

TABLE 6.3: *Ultimate Analysis of ASTM Coals (including moisture)*

	Ultimate Quality + Moisture						
Coal Type	Moisture	Ash	Sulfur	Hydroge	Tot.C	Nitrogen	Oxygen
Meta-Anthracite	13.2	16.4	0.3	1.6	55.7	0.2	12.6
Anthracite	4.3	9.2	0.8	2.8	76.3	0.9	5.8
Semianthracite	2.6	7.3	1.7	3.7	79.3	1.6	3.9
Low-Volatile Bituminous	2.9	5.2	0.8	4.5	80.8	1.3	4.6
Med-Volatile Bituminous	2.1	6.0	1.0	4.9	79.9	1.4	4.8
High-Volatile A Bituminous	2.3	5.1	0.8	5.4	76.6	1.6	8.3
High-Volatile B Bituminous	8.5	9.9	2.6	4.9	59.6	1.2	13.4
High-Volatile C Bituminous	14.4	8.2	3.3	5.0	51.1	0.9	17.2
Sub-Bituminous A	16.9	3.0	1.2	5.0	50.2	1.0	22.8
Sub-Bituminous B	22.2	3.3	0.4	5.4	41.9	0.8	26.0
Sub-Bituminous C	26.6	4.3	0.4	4.8	36.7	0.7	26.6
Lignite	36.8	3.7	0.6	4.4	25.7	0.4	28.5
t = tonne				(weight %)			

(Source: IEA, DOE 1995)

FIGURE 6.2: *Energy Content of ASTM Coals*

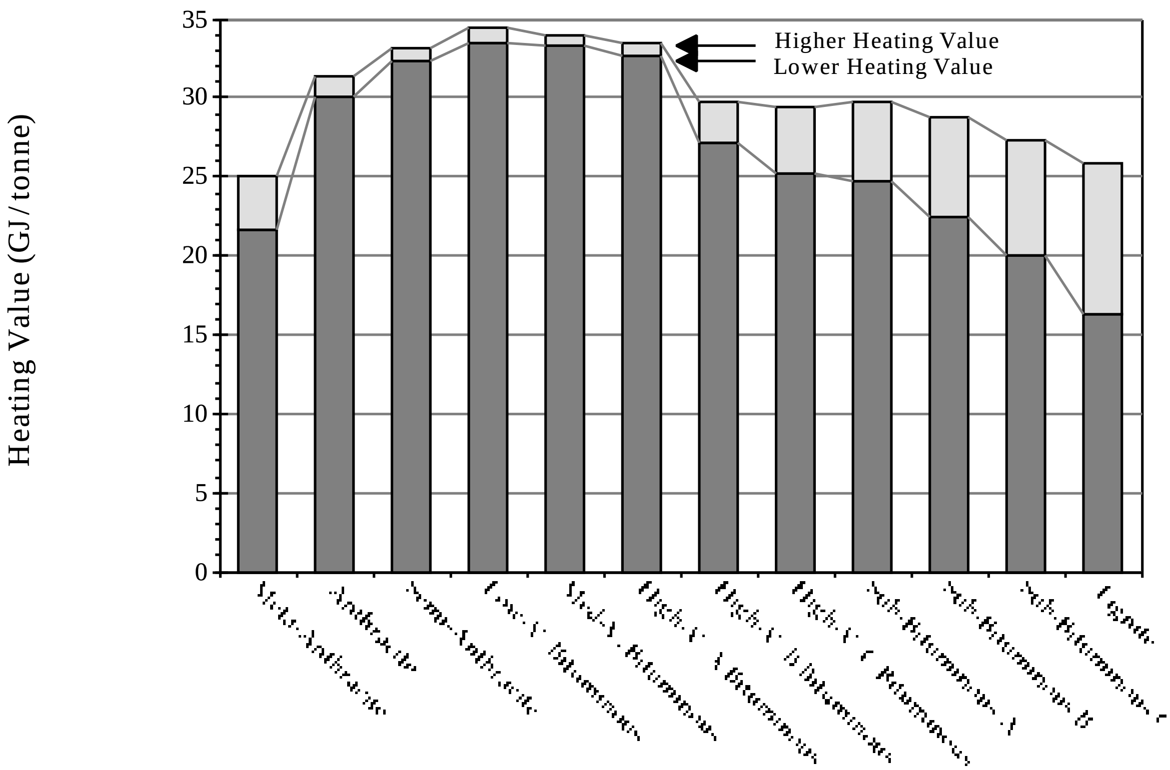


FIGURE 6.3: *Proximate Analysis of ASTM Coals*

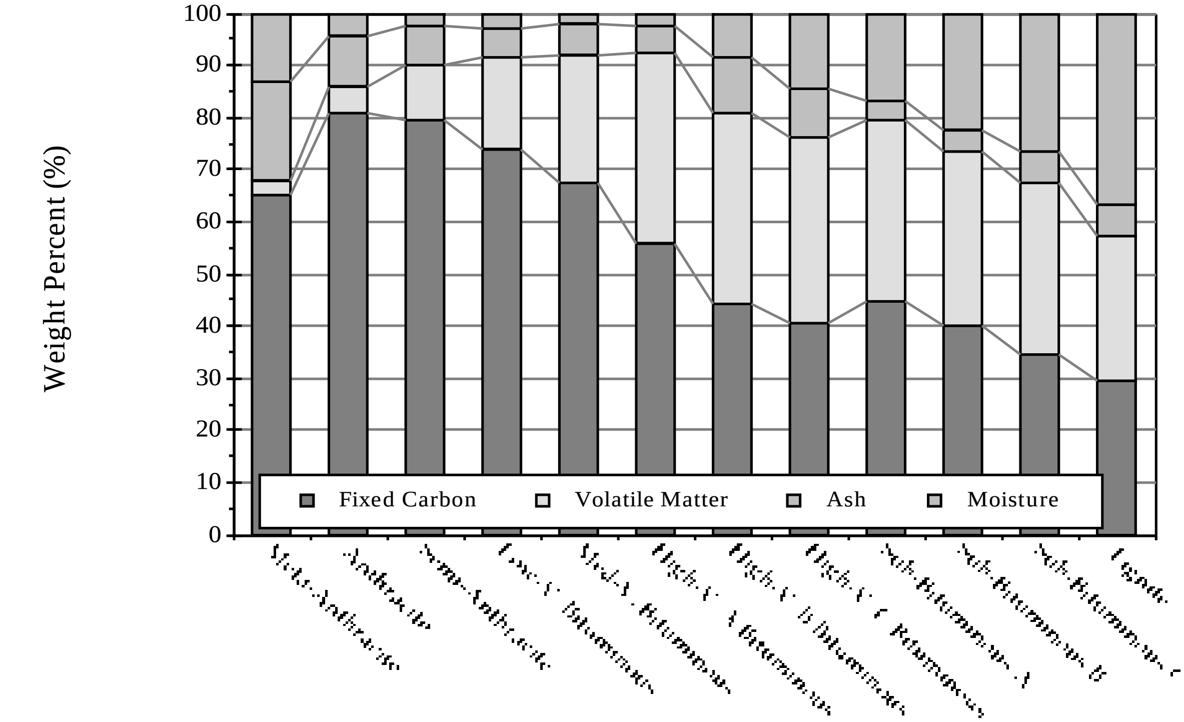
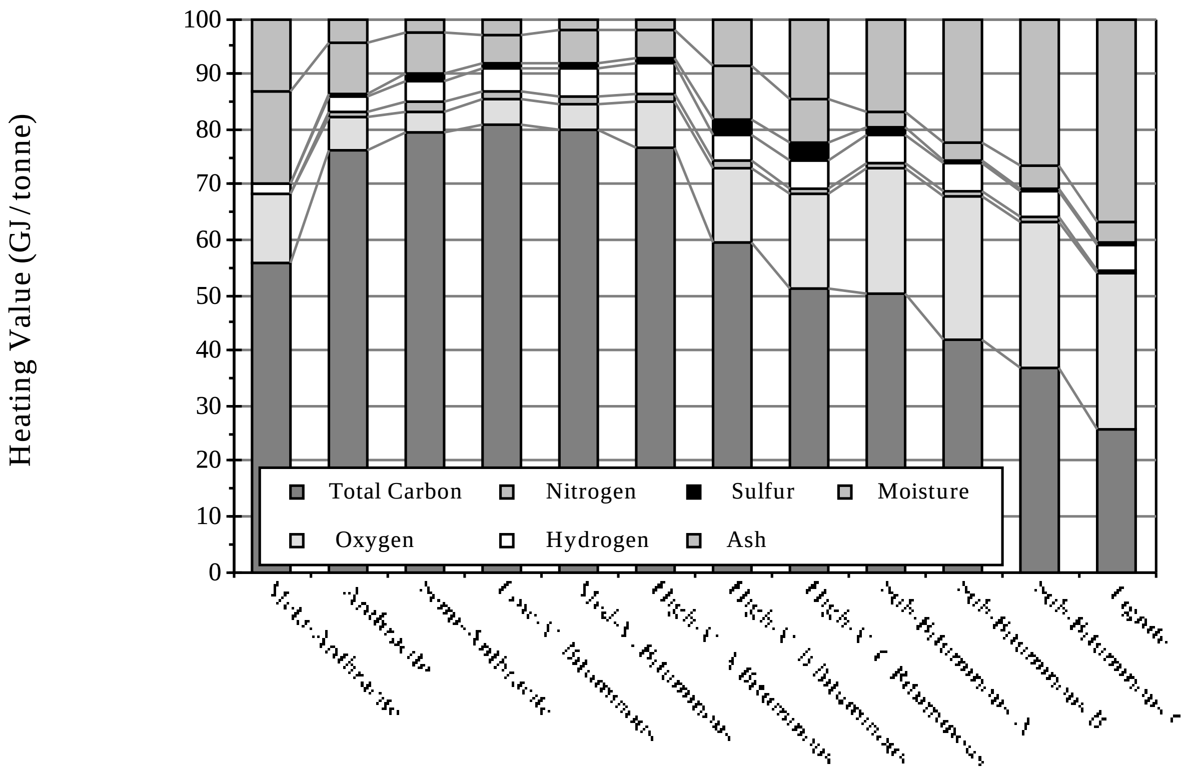


FIGURE 6.4: *Ultimate Analysis of ASTM Coals (including moisture)*



As can be seen by the above tables and figures, energy content is determined roughly by the total carbon content of the coal, with the lower volatile matter bituminous coals, along with semi-anthracite, having the highest energy content. The other components of coal dilute its energy content by reducing the overall quantity of carbon-hydrogen or carbon-carbon chemical bonds, or by absorbing some of the energy contained in the fuel through the elimination of moisture during combustion.

Table 6.4 shows the heating values and proximate analysis for selected standard Chinese coals. As can be seen, these are substantially different from the ASTM coals, due in part to their higher ash content. This results in a lower overall heat content. Since an complete ultimate analysis of standard Chinese coals was unavailable, we used information on ASTM coals, Chinese standard coals, and information provided by SEPRI to craft an equivalent ultimate analysis for steam coals used in Shandong. The next section describes the methods we used to "approximate" ultimate and proximate properties of coal from these information sources. In brief, we used a curve-fitting method to ascertain total carbon content from lower heating values. We then used subtractive analysis to reapportion the percentages of various fuel constituents based upon this carbon calculation.

Table 6.5 shows the properties of coals used by Shandong's larger power plants for 1998. Sulfur contents for most of these power plants were reduced from these levels in accordance with environmental regulations beginning in 1999 (which was reflected in the modeling). As the other components of fuel properties in the 1998 data are more complete (e.g. energy, ash and sulfur content), we used these values to develop baseline fuel assumptions, as described below.

Among the four types of coal used in Shandong for power generation, the chemical composition of the anthracite and lignite categories is relatively close to ASTM standards. Chinese meager coal appears close to ASTM Semi-Anthracite in composition. Chinese bituminous coal appears similar to ASTM Sub-Bituminous A coal.

Table 6.4: *Proximate Properties and Classification of Selected Chinese Standard Coal Types*

	Lower	Proximate Quality			
Chinese Standard Coals	HV	Moisture	Vol.M.	Fixed C	Ash
Anthracite	26.5	9.0	25.8	56.6	8.6
Meager coal	21.4	1.0	12.8	56.8	29.4
Lean coal	24.4	5.4	11.2	57.1	26.3
Weakly caking	29.6	9.0	25.8	56.6	8.6
Non-caking	26.8	11.3	25.4	52.5	10.8
Long flame Coal	22.3	13.5	32.0	43.7	10.8
Brown coal (Lignite)	16.9	30.8	23.7	25.6	19.8
t = tonne	(GJnet/t)	(weight %)			

(Source: China Energy Data Book, 1991, SEPRI Data)

TABLE 6.5: *Coal Energy, Sulfur and Ash Content, Coal Type, Source and Transportation Methods for Shandongs' Major Power Plants*

Power Plant	Lower HV	1998 Composition Sulfur	Ash	Primary Fuel	Primary Fuel Source	Delivery Method
Linyi	24.6	0.44	19.87	Meager	Shanxi	Rail
Liaocheng	24.5	0.42	23.90	Meager	Shanxi	Rail
Heze	23.8	0.50	24.00	Anthracite	Shandong	Rail
Weihai	23.5	0.75	13.20	Bituminous	Inner Mongolia	Rail / Ship
Huangtai	23.4	1.48	23.80	Meager	Shanxi, Shandong	Rail
Shiheng	22.9	1.48	23.90	Bituminous	Shandong	Rail
Weifang	22.7	1.24	26.82	Meager	Shanxi, Shandong	Rail
Jining	22.6	0.61	21.10	Meager	Shandong	Rail
Zouxian	22.6	0.80	21.50	Bituminous	Shandong	Rail
Shiliquan	22.5	1.18	22.67	Bituminous	Shandong	Rail
Qingdao	22.2	2.31	26.00	Meager	Shanxi, Shandong	Rail / Ship
Yantai	22.0	1.62	26.80	Meager	Shanxi, Shandong	Rail / Ship
Nanding	21.9	2.00	28.60	Meager	Shandong	Rail
Laiwu	21.5	2.58	27.90	Bituminous	Shandong	Rail
Longkou	21.5	0.52	16.63	Lignite	Shandong	Mine Mouth
Huangdao	21.5	1.34	28.80	Meager	Shanxi, Shandong	Rail / Ship
Dezhou	21.4	1.23	27.30	Meager	Shanxi	Rail
t = tonne	GJnet / t	(wgt. %)	(wgt. %)			

(Source: SEPRI)

APPROXIMATING CHINESE COAL CHARACTERISTICS

Based on the heating value (LHV, Gj_{net} / tonne), and sulfur and ash contents of a particular coal in our classification scheme, we calculated the balance of the coal's characteristics (total carbon, fixed carbon, volatile matter, ash and moisture) using the following procedures.

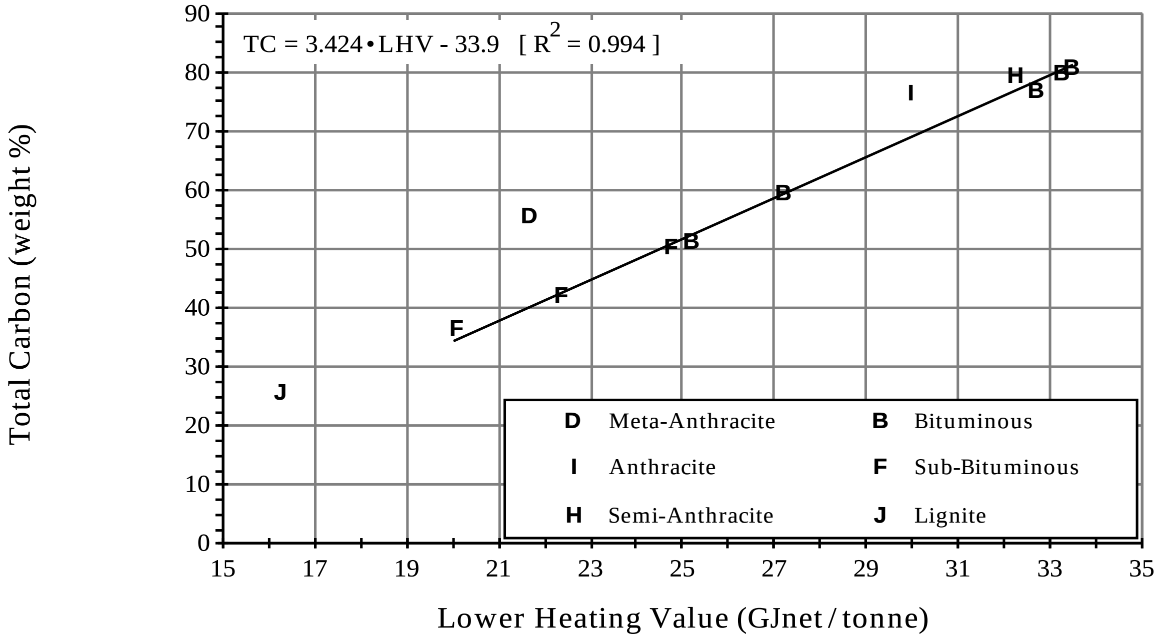
Total Carbon

The total carbon content of coal is closely related to its heating value as carbon related chemical bonds are the primary source of energy released during combustion. Figure 6.5 shows the correlation between lower heating value and total carbon for ASTM coals from Semi-Anthracite through Sub-Bituminous C, with the data plotted for all the ASTM coals in Table 6.2. Since the relation is quite high ($R^2 > 0.99$) we used the resulting equation to determine the weight percent to Total Carbon for Chinese meager and bituminous coals.

$$\underset{\text{(weight \%)}}{\text{Total Carbon}} = 3.424 \cdot \underset{(Gj_{net}/\text{tonne})}{\text{LHV}} - 33.9 \qquad (1)$$

Lignite is on the extension line of the fitted line. We therefore also used the above equation to calculate the total carbon content of lignite. For anthracite, we used an approximate value of the anthracite data given by SEPRI, and assigned as slightly higher carbon content to anthracite with a higher heating value.

FIGURE 6.5: *Correlation of Heat Content to Total Carbon*
(ASTM Coals – Semi-Anthracite, Bituminous and Sub-bituminous)



Fixed Carbon

Fixed carbon partially contributes to the total carbon content of coal. The rest of the carbon content exists in a volatile form. We calculated the fixed carbon content of each coal type according to the ratio of total carbon content to fixed carbon, using ratios approximated from both ASTM and Chinese coal information. These approximate ratios are listed in Table 6.6.

TABLE 6.6: *Ratio of Total Carbon (TC) to Fixed Carbon (FC) by Coal Type*

Coal Type	–	TC / FC
Anthracite		1.00
Meager		1.05
Bituminous		1.12
Lignite		1.00

Ash Content

Chinese coal typically contains a high percentage of ash. Although not directly related, the ash content of coal does affect its heat content due to its dilution effect. Another factor that would reduce the heat content of coal is its moisture. Since coal from Shanxi and Shandong is generally low in moisture and similar in composition, we can make a linear approximation of ash from its heat content. Figure 6.6 shows the relationship between Lower Heating Value and Ash content for the meager and bituminous coals from Table 6.5. (SEPRI) The correlations for the curve fits on both types of coal are not high, but generally acceptable.

Therefore, we determined the ash content of bituminous and meager coal using the following equations:

$$\underset{\text{(weight \%)}}{\text{Ash (Meager)}} = \underset{(\text{Gj}_{\text{net}}/\text{tonne})}{-2.05 \bullet \text{LHV}} + 71.8 \qquad (2)$$

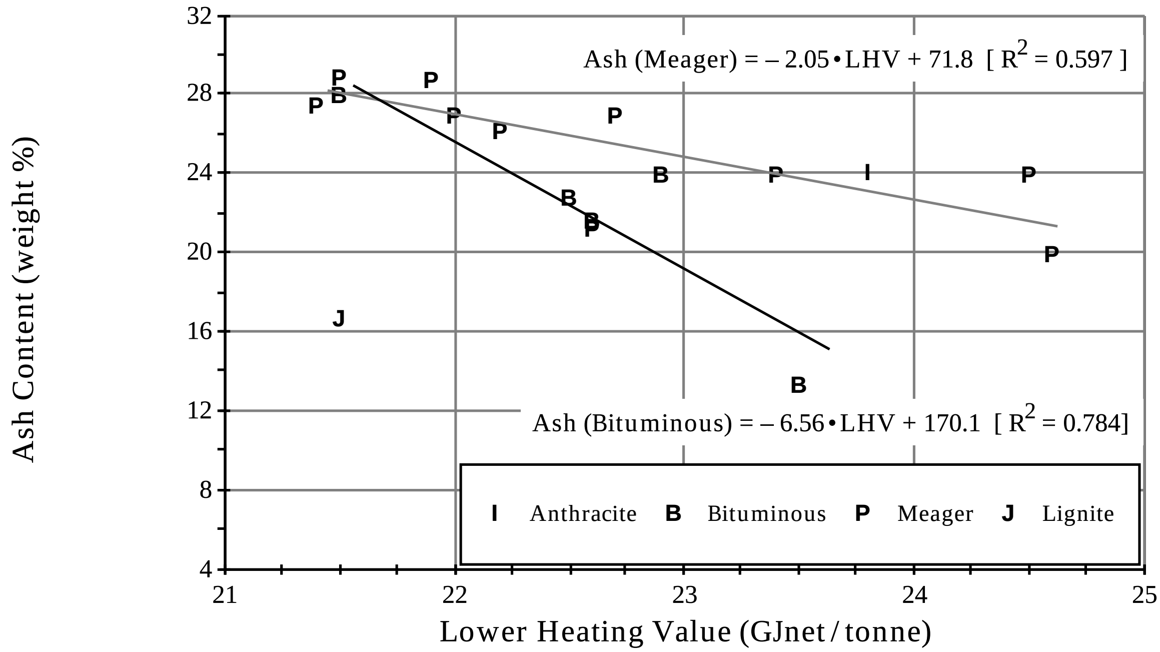
$$\underset{\text{(weight \%)}}{\text{Ash (Bituminous)}} = \underset{(\text{Gj}_{\text{net}}/\text{tonne})}{-6.56 \bullet \text{LHV}} + 170.1 \qquad (3)$$

We assigned the ash content of anthracite based on the anthracite data SEPRI provided, and assigned an ash content for lignite by approximating a value given by SEPRI coal data.

Sulfur Content

We used weight percent sulfur numbers from SEPRI for existing power plants, and generalized for future unit additions and "prepared" coals, as explained in Appendix C.

FIGURE 6.6: *Correlation of Heat Content to Ash Content for Chinese Meager and Bituminous Coals* (SEPRI)



Moisture Content

The moisture content of Shandong steam coal is substantially lower that that of ASTM coals. Table 6.7 shows the differences. We used SEPRI numbers.

TABLE 6.7: *Moisture Content (wgt. %) – ASTM vs. SEPRI Steam Coals*

ASTM Coal Type	Moisture	–	Moisture	SEPRI Coal Type
Anthracite	13.1		2.74	Anthracite
Semi-Anthracite	2.6		1.03	Meager
Sub-bituminous A	16.9		1.35	Bituminous
Lignite	36.8		10.68	Lignite

Volatile Matter

As both proximate and ultimate analysis must separately sum to 100%, we calculated weight percent volatile matter in proximate analysis as the remainder of fixed carbon (calculated via total carbon and the TC / FC ratio) plus ash content (calculated via the ash / LHV equations) and moisture.

CLASSIFICATION OF COALS FOR ELECTRIC SECTOR SIMULATION

Based on the data provided by SEPRI which describes the characteristics of coals currently used in Shandong power generation, and the broader range of coals that we would like to use in ESS scenarios, we have constructed a classification scheme based on coal type, source and method of transport, energy content, and sulfur content. This includes both “raw” coal, and “prepared coal.” (A description of coal preparation techniques, and their possible application to Chinese “raw coals” follows this section.) We selected sulfur content and LHV as primary criteria for categorization because they are the most important coal qualities that determine the thermal and environmental performance of generation units without considering unit-specific information. Moreover, we include categories for coal source, transportation mode and coal preparation methods as they are key determinants of the cost of delivered coal. Baseline assumptions for coal costs, and coal cost uncertainties are described in “Coal Cost Assumptions and Coal Cost Uncertainty Development.”

The simulation input being used for ESS has a four character limit for fuel names. Accordingly, the first character refers to the source and mode of transport of the coal being described. The second character refers to the coal type (anthracite, bituminous, etc.) and whether the coal has been treated or not. The third character refers to the sulfur content of the coal, and the fourth character refers to the heat content of the fuel.

All the resulting coal types of possible use in the ESS scenarios, including assumptions for energy content, chemical composition and base costs are described in Appendix C.

TABLE 6.8: *ESS Coal Classification Code Table*

Digit 1 - Transportation Method

Coal Source	Mine Mouth	Rail	Rail / Ship
Shandong	M	D	–
Shanxi	P	X	S
Inner Mongolia (Batou)	–	–	B

Digit 2 – Coal Type

Coal Type and Treatment	Type Code
Anthracite	A
Meager – Raw	M
Meager – Prepared	R
Meager-Washed	G
Bituminous – Raw	B
Bituminous – Prepared	P
Bituminous – Washed	T
Lignite	L

Digit 3 (Sulfur Content) & Digit 4 (Energy Content)

Sufur Content (%S)						
2.0 ≤ %S	(5)	51	52	53	54	55
1.5 ≤ %S < 2.0	(4)	41	42	43	44	45
1.0 ≤ %S < 1.5	(3)	31	32	33	34	35
0.5 ≤ %S < 1.0	(2)	21	22	23	24	25
0.0 < %S < 0.5	(1)	11	12	13	14	15
		(1)	(2)	(3)	(4)	(5)
Sulfer & Energy Content at Midpoint		LHV < 22	22 ≤ LHV < 23	23 ≤ LHV < 24	24 ≤ LHV < 25	25 ≤ LHV

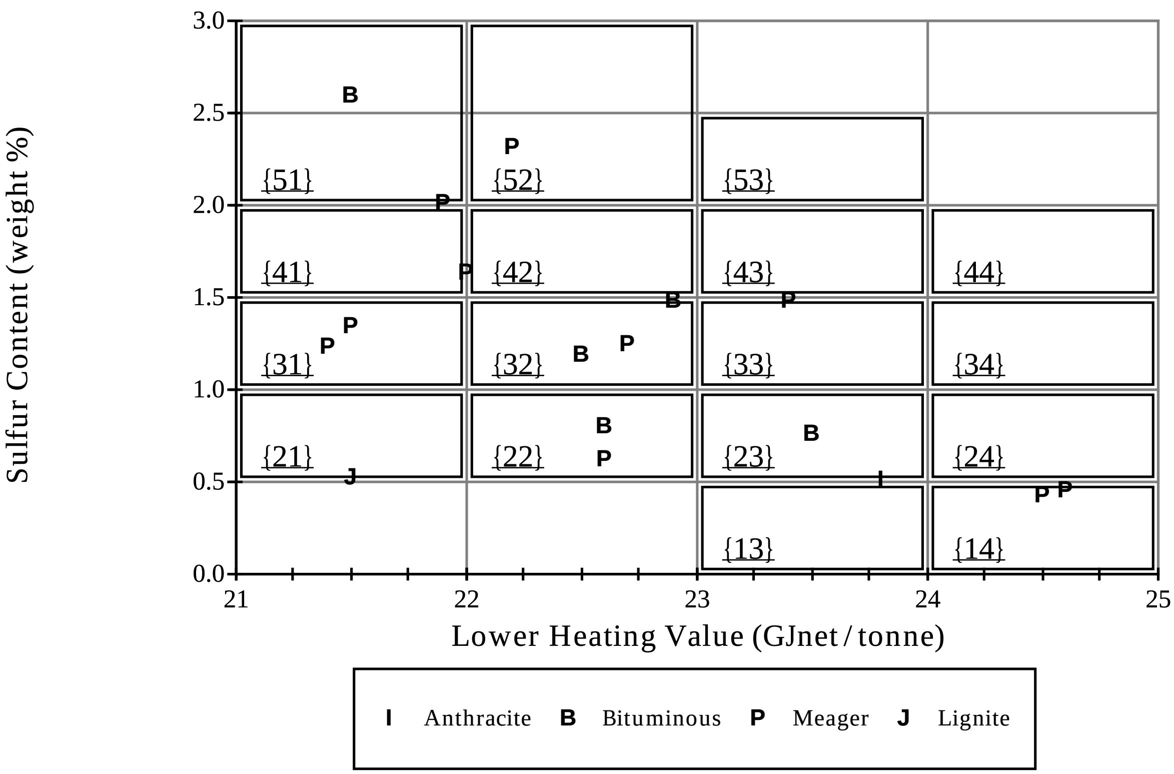
Energy Content (LHV – GJn / tonne)

empty

Example: **DM32** Shandong Meager Coal (Raw), Transported by Rail, 1.25%S, 22.5 GJn / tonne

From the sulfur and lower heating value graph of the Shandong generation coal data (Figure 6.7), we can see that most coal has a sulfur content between 0.5 to 2.0% and lower heating value between 21 to 25 GJ_{net} / tonne. The coal classification for ESS divides sulfur content into five intervals (1 to 5, by half a percentage point sulfur content) and heat content into four classes (1 to 4 by 1 GJ intervals). Seventeen bins are shown in Figure 6.7, with no coals residing in the lower left two bins or the upper right three bins. These divisions correspond to the naming scheme for generic coal as indicated in Table 6.8. For each type of coal (bituminous, meager, anthracite, lignite), we chose several generic coal categories with different sulfur and LHV qualities based on currently available coal quality information and on conjectured future coal quality.

FIGURE 6.7: *Lower Heat Content vs. Sulfur Content of Current Shandong Generation Coal*



As the specific sulfur and energy content for the larger Shandong power plants is known, we will use unit specific multipliers to calculate their emissions. Otherwise the generic fuels described here will be applied to smaller existing Shandong generation, as well as to future generation. We typically choose the "mid-point" within each bin or "cell" as a representative data point. For example, coal with code {22} with sulfur content between 0.5 to 1.0% and LHV between 22 to 23 GJ_{net} / tonne, will be defined as 0.75 % sulfur and 22.5 GJ_{net} / tonne energy content. The exceptions are the cells with low sulfur content ({13} and {14}), to which bins we ascribe a 0.5% sulfur content as ultra-low sulfur content coal is rare.

OVERVIEW OF COAL PREPARATION TECHNOLOGIES

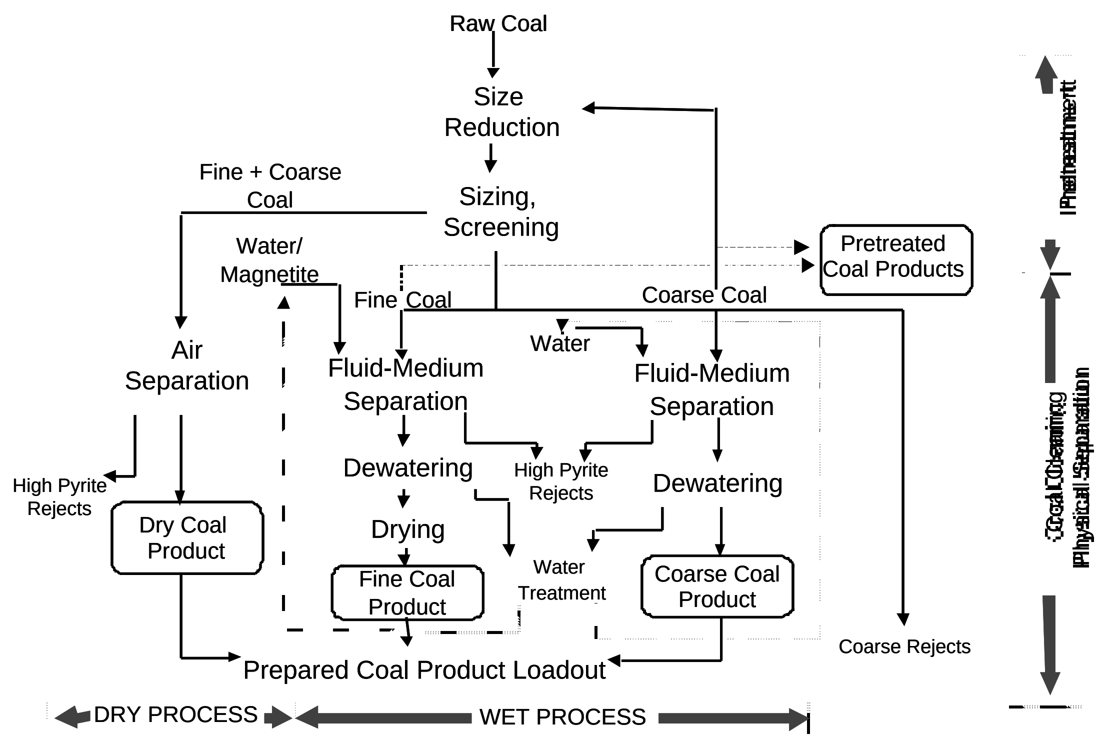
Coal preparation-often called cleaning, beneficiation or processing-is a process by which impurities are removed from coal to improve its heating value and also to achieve desired specifications for ash, moisture and sulfur content. (USEPA, 1995, Speight, 1995) The operation involves two parts; pretreatment and separation. Separation methods can generally be divided into two categories: dry process and wet process. In the Chinese coal industry, the analogous terms "coal sorting" and "coal washing" are commonly used. Coal sorting generally refers to coal preparation using dry methods (mechanical and air separation), and coal washing typically involves fluid media (water, oil, or other heavy media) separation. In our study, we do not specify the particular methods that are used for preparation, but rather the final quality of prepared coal. However, as the discussion below indicates, various techniques are implied.

Figure 6.8 shows a simplified process flow diagram for a typical coal preparation plant. Initially, the raw coal is broken, crushed and screened using a series of machines in order to achieve certain desired sizes and provide a uniform coal feed for separation. This process is often called pretreatment. The extent of size reduction at this stage depends on the final use of the coal as well as on its condition. For example, coal for power plant use may require a finer-sized coal with diameter less than 1 mm. (Speight, 1995) On the other hand, coarse coal is often preferred in the coking industry.

The purpose of the cleaning process at the second stage is to physically separate coal from its impurities which are not chemically bound to the coal. A number of methods are commonly employed. Pneumatic (air), mechanical and other similar techniques are often referred to as dry-separation technologies as do not require fluid media. Dry processes are understandably preferred in areas where water is in limited supply. Shanxi Province, for example, has limited water resources which greatly constrains coal preparation activities at or near the province's mines. Development of dry cleaning coal plants is desirable in Shanxi and its importance has been reiterated. However, the costs of dry cleaning plants and the quality of final product vary greatly and are highly dependent on the technology used.

Wet processes have gained popularity due to their effectiveness and ease of operation. Crushed coal is separated into coarse coal, fine coal, and sometimes ultra-fine coal, with various fluid media used to separate out the impurities for each grade. Fluid media such as water, dense media (most commonly a mixture of magnetite and water), and oil are used for separation of coal from other impurities. Froth floatation, hydraulic and dense medium methods are often utilized, all of which rely on impurities sinking and the carbon rich coal floating as the primary mechanism of separation. The coal is then recovered from the fluid and dewatered. This document does not go into the details of coal pretreatment and separation. However, the smaller the size of the crushed coal, the more difficult to reach efficient separation using the froth floatation method. In general, the efficiency of separation is greatest in dense medium systems; and least in froth floatation systems. (Williams, 1981)

FIGURE 6.8: *Simplified Coal Preparation Process*



The extent of coal cleaning and quality improvement depends on the final uses of coal. Industries which require high quality coal may require the use of expensive equipment. For electricity generation however, moderate coal quality is generally suitable, though using higher quality coal in electricity generation can help to reduce pollutant emissions as well as the costs of transportation, emissions control and waste treatment. A certain degree of ash reduction is acceptable for this purpose. According to Yeh (1999), the average ash reduction in Chinese coal achieved through cleaning is approximately 40%. In the ESS scenarios, we use this 40% reduction in ash content to distinguish “prepared coal” from its “raw coal” feedstock.

DETERMINING PROPERTIES OF PREPARED COAL

As discussed above, our coal classification system presents a list of prepared coal that is used for power generation. We determine the quality of various prepared coals by the extent of ash reduction achieved from which particular raw coals they originated. To develop a database of prepared coals, we apply a 40% reduction in ash content to all bituminous and meager coal produced in Shandong and Shanxi. Anthracite is not processed because it generally has lower ash content. On the other hand, our analysis rules out lignite cleaning as it is not economical to process or transport and is therefore typically only used it in mine-mouth plants.

Because coal composition is expressed in percentage terms, and percentage composition changes after some of the ash is removed, the resulting prepared coal must be re-ratioed on a per tonne chemical composition and energy basis. In order to achieve 40% less ash in prepared coal, we apply a 45% reduction in ash to all raw (unprocessed) bituminous and meager coal. However, ash reduction varies slightly from 40% in different coal classes because of varying composition in the raw coals from which they stem. Therefore coal preparation results in an approximate (0.35 times 0.4) 14% reduction in sulfur as well. We present more detailed assumptions regarding calculation of prepared coal properties below.

Proximate Properties

For ease of calculation and for re-normalizing the non-ash constituents of coal, we assume that in the pretreatment and dry separation production stages these components (fixed carbon, volatile matter and moisture) are not diminished. This may be optimistic, as some fixed carbon and volatile matter may be lost. However, an optimized coal cleaning facility should retain as much of the original carbon as possible. Therefore, we apply an ideal condition (0% loss) for carbon content in the ESS study. In addition, moisture in coal would increase if wet cleaning methods were used. However, because of water resource limitations in Shanxi and Shandong, we assume use of dry methods. Therefore, moisture content remains unchanged.

Sulfur Content

As discussed above, mineral (pyritic) sulfur can be reduced as ash is removed. Assuming that 35% of the total sulfur is mineral (which is the mid-point of the SEPRI data of 30-40%), and that mineral sulfur is homogeneously distributed in ash, thus approximately 14% (0.35 x 0.40) of the total sulfur would be reduced through the preparation process.

Total Carbon and Lower Heating Value

We assume that the ratio of total carbon to fixed carbon for each type of coal (bituminous and meager) remains unchanged. As the ratio of total carbon increases with the removal of the ash, the heat content of the fuel must be recalculated using the inverse of equation (1) above. The resulting equation is:

$$\underset{(Gj_{net}/\text{tonne})}{\text{LHV}} = \underset{(\text{weight }\%)}{(\text{Total Carbon} + 33.9)} \;/\; 3.424 \qquad (4)$$

THE IMPACTS OF COAL PRETREATMENT

As a result of ash removal in the preparation process, energy content significantly improves when coal is cleaned. For example, using these basic assumptions, DM32 (Shandong meager coal) has not only 14% less sulfur (1.25% to 1.08%) but 8% more thermal energy per tonne (22.5 to 24.3 Gj_{net}/tonne), becoming DR43 coal.

While these are not dramatic changes in fuel quality, given the quantity of coal consumed in our simulation they will be significant. We apply a flat cost of 5 ¥/tonne to the cost of prepared coal, plus the roughly 9% to 15% increased raw coal cost depending on the initial ash content of the raw coal. This is offset to some degree by the reduced transportation costs on a per unit energy basis.

One surprising potential impact of coal pretreatment may be the operational benefits and related increased availability of coal fired units. This includes more than just the reduced operating costs associated with coal handling and sulfur and particulate removal.

Coal ash affects combustion in many ways. In addition to diluting coal's energy content there are metal oxides (particularly iron oxide) which "soften" the ash, contributing to "fireside fouling," also call slagging or scaling within coal boilers. (Speight, 1994) The formation of fouling deposits is associated with the reduction of ferric oxide (Fe_2O_3) to ferrous oxide (FeO) which generates "clinker" and causes slag formation on the superheater and reheater tubes. (Speight, 1994, Sue, 1999) Total alkali metal content of coal also contributes to fouling. Coal having more than 0.6 weigh-percent alkali metal can cause an increased amount of deposits that cannot be easily removed by the soot blowers. (Speight, 1994)

Fouling results in reduced thermal conductivity of heat exchangers and other significant operational problems. Fouling of the fireside of boiler tubes not only reduces the boiler efficiency and increases fuel use, but also requires frequent soot blowing, and increased maintenance requirements in terms of time and money for removing slagging deposits. In severe cases, overheating due to fouling can cause the rupturing of superheaters and reheaters. (Sue, 1999) Consequently, production losses during planned and forced outages can pose major costs to power producers.

According to a recent report by Sue (1999), fouling of boilers, including the overheating of superheaters and reheaters and overall lower efficiency, resulted in a new 600MW unit having a capacity factor of only 45-50% during the first three years of operation. In particular, Unit 3 of Harbin's Third Plant experienced a forced outage frequency of over 40 times per year during its first two years of operation (1996 and 1997).

In ESS scenarios, we assume scheduled maintenance of 10 weeks/year and an 8% forced outage rate for raw coal units, or a maximum availability of 74% capacity factor and 6490 hours of generation per year. The prepared coal units require less maintenance and also have diminished chances of forced outages. Our assumption for prepared coal units is 8 weeks of scheduled maintenance and a 5% forced outage rate. The resulting capacity factor and total available generation hours are 80% and 7020 hours respectively (See Table 6.9).

Table 6.9 illustrates some of the unit availability benefits that may result from the use of reduced-ash coal in typical large Chinese coal-fired units. It should be noted that these benefits reach beyond unit-specific operational savings. System-wide investment benefits may also be large. As Shandong has nearly 20 GW of installed capacity serving a 8.5 GW peak load, the ability to increase unit output and cut the capacity reserve margin from its current 60% to the international common practice of 25% to 30% can result in substantial savings.

TABLE 6.9: *Potential Availability Benefits of Prepared Coal Use*

		Raw Coal Fueled Units	*Prepared Coal Fueled Units*
Capacity Factor	(%)	74	80
Scheduled Maintenance	(Wks/yr)	10	8
(Equivalent) Forced Outage Rate	(%)	8	5
Total Avaiable Generation Hours	(Hrs/yr)	6490	7020

EMISSIONS FROM COAL COMBUSTION

The environmental performance of coal combustion for power generation is determined not only by coal quality, but also by the combustion conditions and pollution control mechanisms of the generation units. Improvements due to installing pollution control devices can thus be modeled in unit-specific simulation. However, the emissions of some pollutants can be stoichiometrically calculated by assuming complete oxidation of the combustible elements in coal. Such pollutants include sulfur dioxide (SO_2), carbon dioxide (CO_2), and total ash (including fly ash and bottom ash). In the ESS simulation, the emissions of SO_2 and CO_2 are determined by stoichiometry from the fuel assuming complete oxidation, minus the 1% of total carbon and 4% of sulfur that typically stays fixed in the ash wastes. This subtraction is derived from the stack fractions for carbon and sulfur, 99% and 96%, respectively. The formulae used to calculate the total emissions of SO_2 and CO_2 are:

SO_2 emissions: (kg per GJ_{net} of fuel energy consumed) =
(Molecular Weight of SO_2 (64) / Molecular Weight of S (32)) / LHV *1000

CO_2 emissions: (tonne per GJ_{net} of fuel energy consumed) =
(Molecular Weight of CO_2 (44) / Molecular Weight of C (12)) / LHV

Other pollutants such as nitrogen oxides (NO_x) and particulate emissions are highly dependent on the combustion conditions within individual units. We use representative data from a 300 MWe generation unit in our baseline emissions rates for the various coal classifications. These rates for NO_x and total suspended particulates (TSP) emissions serve as the basis upon which unit-specific multipliers work.

Prepared by Chia-Chin Cheng with the assistance of Stephen Connors, Christopher Hansen and Jennifer Barker

CHAPTER NOTES:

Due to insufficient detailed information about steam coal used in Shandong power plants, we have applied various assumptions and approximations in order to formulate the generic coal data for ESS scenarios. Fortunately, ESS scenarios are inherently comparative in nature, and therefore can tolerate a higher degree of uncertainty in input data than other methodologies. Our generic coal assumptions are of course subjected to review by the CETP Stakeholder Advisory Group, and have been periodically revised as more information has become available.

Chapter 7: Coal Cost Assumptions and Coal Cost Uncertainty Development

Introduction

As coal costs typically constitute the largest portion of the operational cost of coal-fired power plants, they are an important parameter in the ESS study. In our analysis, coal quality is the main factor determining its cost. That is, coal with superior combustion performance that generates a greater amount of heat with fewer impurities and pollutants has a higher economic value.

The source of coal is another important factor and is closely related to transportation cost. The steam coal used for power generation in Shandong comes from both indigenous sources and other provinces. Thus transportation modes and distance to generating units also help to determine the overall cost of steam coal used for power generation. In the current Chinese coal market, pricing mechanisms do not directly follow this rationale due to distortions introduced by state subsidies and by differing policies among the various ministries influencing wholesale prices. It is therefore difficult to find evidence of consistently applied pricing rules in this realm. Nonetheless, we chose to regularize coal costs in accordance with established convention by basing them on quality, transportation mode and point of origination.

The cost of coal in Shandong will obviously vary over the study period's 25 year timeframe (2000-2024). Many factors will influence its cost, such as market mechanisms, competition, production technology, transportation, government policies, and other economic conditions that shape demand for coal. Because it is impossible to capture all the factors that will determine future coal cost, a precise "forecast" of coal costs is impossible. It would also be inappropriate to base the study on the optimization of the system to formulate precisely modeled forecasts of the future change. Nevertheless, future price projections are necessary in order to describe the cost variation of coal and the resulting changes in the electricity sector.

In this document, we describe four coal cost uncertainties/trajectories that should be of interest to the stakeholders, as they incorporate current coal pricing reforms and potential mining technology improvements, as well as other factors associated with coal production and transport.

We have named these four coal cost uncertainties:

a) Business as Usual (I),
b) Market Stabilization (O),
c) Production Innovation (U), and
d) Aggravated Transportation (A).

BACKGROUND

Until January 1994, Chinese coal was produced under a dual system. There were two types: allocated coal from state, provincial and county mines and free market coal, which is from small township mines (EIA, 1999). Allocated coal was priced by the State, and free market coal was sold at negotiated prices.

The dual system was abolished in January 1994 (EIA, 1999), which had the effect of increasing prices charged by State Own Enterprises (SOEs) to a more realistic level given their production costs. Yet, the liberalization of coal prices has also encouraged the entry of many small mines, stimulating overproduction and price drops in this market sub-segment since 1997. These factors, taken together, complicate the desired transformation to market pricing of Chinese coals. Given the current transitional situation, steam coal prices in Shandong and elsewhere in China tend to reflect the outcome of bilateral price negotiations subject to inconsistent government review than they do conventional commodity pricing protocols (IEA, 1999).

DETERMINATION OF COAL COSTS

At present, Shandong generation coal comes from various sources and is transported to power plants via different methods depending on the coal's source and destination. Anthracite, meager, and bituminous coal mined in Shandong province are most commonly transported by rail. In our analysis limit lignite to mine mouth use as it is not economical to transport such low energy content fuels long distances.

Shanxi mines are large suppliers of generation coal to Shandong. Transportation by rail or a combination of rail/ship is available depending on the location of mines, and the final destination in Shandong. Coal hauled by different modes is considered separately in the ESS assumptions because the resulted transportation costs are different. High quality Inner Mongolian coal is also used for generation to reduce the environmental burden of certain power plants.

As described in the chapter "Classification of Steam Coal for Electric Sector Simulation Scenarios," the coal used in ESS scenarios is categorized according to its lower heating value (LHV, Gjnet/tonne) and sulfur content (weight % S). As mentioned above, the ESS introduces certain rational pricing mechanism to coal costs. We separate coal price (cost to power plants) into raw coal cost, preparation cost, and transportation cost.

Raw coal cost is based on the energy content (LHV) of the coal. We modified a pricing formula used for exported coal to Taiwan and Korea from Shuanyashan Coal Bureau (Zhang & Guo, 1999) to calculate the price, based on the deviation of actual heating value from contracted heating value (28.47 GJ/tonne). The original formula is:

$$\text{Coal Price (raw coal)} = \text{baseline price} \times (1 - (28.47 - LHV)/28.47 \times 1.1) \qquad (1)$$

We then calculate different baseline prices for all four coal types (anthracite, meager coal, bituminous, and lignite) according to this formula using LHV and price data provided by SEPRI (see Table 7.1).

TABLE 7.1: *Baseline Prices for Raw Coal Price Calculation by Coal Type*

Coal Type	Baseline Price Yuan/Tonne
Anthracite	169
Meager	192
Bituminous	194
Lignite	278

The price of prepared coal is based on the production costs. It is determined by taking the total cost of raw coal going into preparation process to produce one tonne of processed coal, plus a 5 Yuan/tonne processing cost. The formula we used to calculate the cost of prepared coal is:

$$\text{Cost of Total Raw Coal for Producing 1 Tonne of Prepared Coal} \times (1/\ \text{weight \% of original coal in prepared coal}) \times 100 \qquad (2)$$

We determine transportation costs by production location and transportation mode. Coal produced in Shandong requires only rail transportation. However, Shanxi coal comes partway to Shandong via a dedicated railroad from Shanxi's major mines to the port city Qinhuangdao northeast of the Shandong Peninsula. The coal is then loaded into barges and shipped to many main Chinese coastal cities, including those in Shandong.

Though shipment by rail is more expensive than by barge, transporting Shandong coal for generation costs less than Shanxi coal mainly due to its relative proximity to delivery points. We determined transportation costs based on the SEPRI data and on recent transportation costs published on the Coal Information Network of China's website (2000). The assigned transportation costs are listed in Table 7.2.

TABLE 7.2: *Transportation Cost of Shandong Generation Coal by Production Location and Transportation Mode*

Production Province	Transportation Mode	Code	Tranportation Cost (Yuan/Tonne)
Shandong	Rail	D	25
Shanxi	Rail	X	40
	Rail/Ship	R	50
Inner Mongolia	Rail	B	50

UNCERTAINTIES FOR FUTURE STEAM COAL COSTS

After aggregating the components of delivered coal costs for the base year (1999), we use four fuel price trajectories for steam coal to examine the comparative performance of strategies under fuel cost uncertainty. The first three trajectories capture the changes in market structure and production technology of raw coal: Business as Usual (Bus<u>i</u>ness–I), Market Stabilization (C<u>o</u>mpetitive – O) and Production Innovation (Prod<u>u</u>ctive–U).

The Business as Usual Case simply assumes that coal costs escalate with inflation. The other cases capture factors affecting possible coal costs in the future. The (O) and (U) uncertainties deal with investments in mining technology and market structure. The fourth coal cost uncertainty, Aggravated Transportation (<u>A</u>ggravated–A), relates to possible coal transport bottlenecks and the need to invest in rail transport infrastructure. This uncertainty will be described in the next section.

Historical coal prices in China escalated with few fluctuations as a result of the planned economy, SOE dominated production, and price control policies. ESS scenarios anticipate that that prices for steam coal will likely continue to follow this trend in the short run due to continued price controls and SOE protection policies in spite of sector liberalization. However, in the long run, it is quite possible that coal prices could decrease if inefficient SOEs exit the market and/or others invest in improved production equipment and improve managerial efficiency. Fully open coal markets and increased competition from private enterprises may also help to drive prices down. We capture this anticipated market stabilization/maturation process in the Market Stabilization (O) trajectory.

The third trajectory captures possible technology improvements in the mining sector that will also help to drive coal prices down in a more aggressive manner. For example, over the past twenty years worldwide coal prices have decreased in nominal terms due to mechanized mining technology and economies of scale as shown in Table 7.3. In China, SOE mines are beginning to introduce modern machinery and mining technology to increase productivity. And, as the market evolves toward freer pricing mechanisms, the penetration of modern technology should help to improve the productivity of coal mines, driving prices down further. The Production Innovation (U) trajectory represents this possible penetration of these technologies.

TABLE 7.3: *Change in Coal Price from 1986 to 1999, US and World Average*

	World Average	US mines	World Average	US mines
Year	$/tonne	$/tonne	Δ%/yr	Δ%/yr
1985	49.5			
1986	47.4	26.2	-4.24	
1987	45.3	25.4	-4.43	-3.03
1988	44.1	24.3	-2.65	-4.33
1989	43.5	24.1	-1.36	-1.13
1990	43.8	24.0	0.69	-0.27
1991	43.5	23.7	-0.68	-1.24
1992	42.3	23.2	-2.76	-2.14
1993	41.7	21.9	-1.42	-5.61
1994	40.8	21.4	-2.16	-2.22
1995	39.6	20.8	-2.94	-2.99
1996	38.7	20.4	-2.27	-1.75
1997	38.1	20.0	-1.55	-1.95
1998	37.8		-0.79	

Data Source: EIA website, 1999 Data, World Averages are calculated from $/MMBTU using 30.0 MMBTU/tonne LHV

The three trajectories are shown in Figures 7.1 and 7.2 in different ways. Figure 7.1 shows the trajectories in 1999 Yuan (excluding inflation) compared to the Base Case (no change over the 25 years). The rate of change of the three trajectories is listed in Table 7.4. In the Market Stabilization Case, price goes up in the first few years in a rate of 2% per year above inflation due to price control policies and increasing demand. Then the growth rate slows and eventually stabilizes at – 2 % per year due to competition and improvements in production and managerial efficiency.

In the Production Innovation uncertainty, coal prices increase the first five years before penetration of modern mining technologies takes place. Then prices decrease at higher rates as the technological introductions spread. The decreasing rate remains at 6% per year for the last few years.

Figure 7.2 shows the change of raw coal costs due to inflation. The cost of coal is expressed in nominal terms (future Yuan) in this case. We assume inflation escalates from zero in the first ten years of our study as China recovers from recent deflation, then remains flat at 5% annually for the rest of the study period. In the Market Stabilization case, coal costs increase in nominal terms after the introduction of inflation. However, in the Production Innovation Trajectory, the nominal price still goes down in later years even with the influence of inflation. This reflects a total annual growth rate of –2%, which is similar to the growth rate of world coal prices over the past decade.

TABLE 7.4: *Modeled Growth of Coal Cost Trajectories*

		Cost Escalation Factors					
		Without Inflation			With Inflation		
Year	Inflation Rate	Business as Usual (I)	Competitive Coal (O)	Productive Coal (U)	Business as Usual (I)	Competitive Coal (O)	Productive Coal (U)
1999							
2000	0.00	0.00	2.00	2.00	0.00	2.00	2.00
2001	0.50	0.00	2.00	2.00	0.50	2.50	2.50
2002	1.00	0.00	2.00	2.00	1.00	3.00	3.00
2003	1.50	0.00	1.00	1.00	1.50	2.50	2.50
2004	2.00	0.00	1.00	1.00	2.00	3.00	3.00
2005	2.50	0.00	0.00	0.00	2.50	2.50	2.50
2006	3.00	0.00	0.00	-1.00	3.00	3.00	2.00
2007	3.50	0.00	-1.00	-1.00	3.50	2.50	2.50
2008	4.00	0.00	-1.00	-2.00	4.00	3.00	2.00
2009	4.50	0.00	-1.00	-3.00	4.50	3.50	1.50
2010	5.00	0.00	-2.00	-3.00	5.00	3.00	2.00
2011	5.00	0.00	-2.00	-4.00	5.00	3.00	1.00
2012	5.00	0.00	-2.00	-4.00	5.00	3.00	1.00
2013	5.00	0.00	-2.00	-4.00	5.00	3.00	1.00
2014	5.00	0.00	-2.00	-5.00	5.00	3.00	0.00
2015	5.00	0.00	-2.00	-5.00	5.00	3.00	0.00
2016	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2017	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2018	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2019	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2020	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2021	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2022	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2023	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
2024	5.00	0.00	-2.00	-6.00	5.00	3.00	-1.00
	(Δ% / yr)	(Δ% / yr, w / o inflation)			(Δ% / yr, w / inflation)		

FIGURE 7.1: *Raw Coal Cost Trajectories* (excluding inflation)

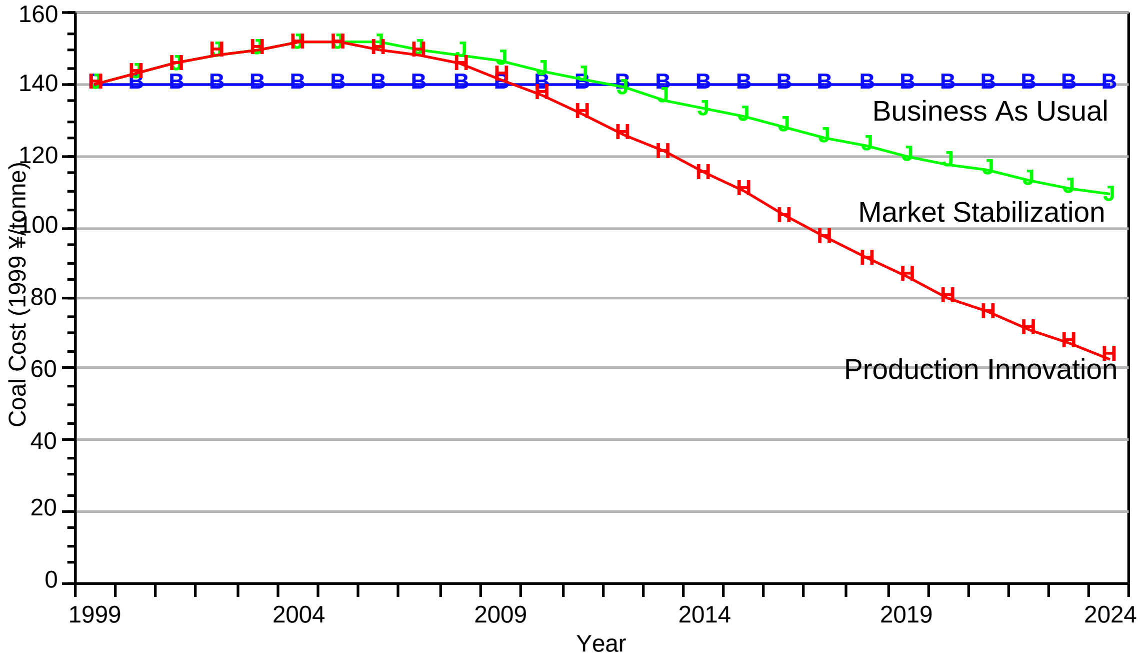
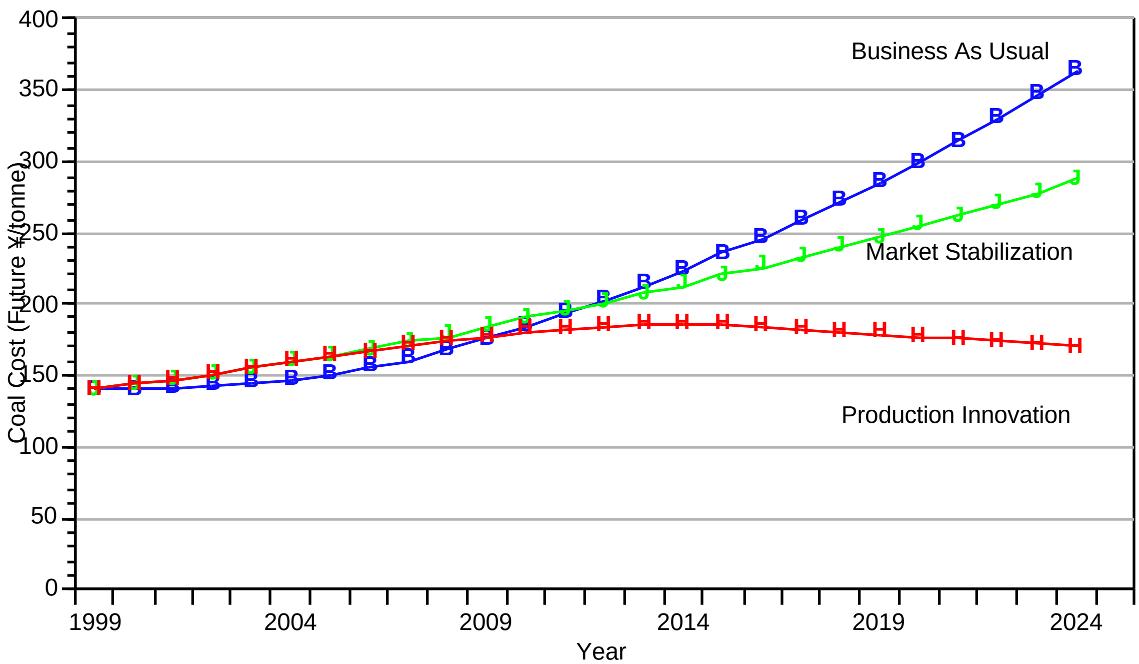


FIGURE 7.2: *Raw Coal Cost Trajectories* (future Yuan / tonne, including inflation)



Note that we introduce no coal price volatility in these uncertainties. However, if the price fluctuation is to be modeled more accurately in the future, we can perhaps expect larger policy and innovation-driven fluctuations in the first 5 to 10 years before market maturation. For simplicity, we assume that coal preparation costs increase with inflation. In a future study, steeper escalation of preparation costs may be needed as the result of requirements for installation of advanced coal preparation technologies to obtain higher quality prepared coal.

UNCERTAINTIES FOR FUTURE COAL TRANSPORTATION COST

Delivered coal costs take into account transportation costs, which may also vary over time due to changes in transportation capacity, policy and technology. Steam coal used in Shandong comes predominantly from mines in the province, and those in Shanxi Province. Transportation bottleneck problems are less prominent for coal produced in Shandong since most power plants have designated railroads from major coal mines. However, coal transported from Shanxi may face transportation bottlenecks as most coal produced in Shanxi relies on only two ports (Yantai on Shandong Peninsula and Qinghuangdao southeast of Beijing) for export to other coastal provinces and abroad. Large demands for coal transportation from Shanxi may over the long-term pose constraints to major coal-shipping routes when the railroads, and port facilities reach their capacity limits.

In our scenarios we modeled two transportation cost uncertainties. In the Business as Usual, Market Stabilization, Production Innovation cases, we only increased transportation costs with inflation. The Aggravated Transportation case includes the effects of escalated transportation costs due to railroad congestion for coal transported from Shanxi, and therefore a need to invest in railroad infrastructure. We use a two-stage escalation trajectory to represent the saturation of rail capacity over a long time frame. We assumed no transportation constraint for coal produced in Shandong and the transportation cost therefore varies only with inflation. The transportation costs for other provinces and freight modes are shown in Table 7.5. The variations of delivered coal costs from different provinces with various transportation measures in the Market Stabilization and Production Innovation cases are shown in Figures 7.3 and 7.4. Figure 7.5 compares the delivered Shanxi coal cost in Aggravated Transportation Case with the Business as Usual Case in both 1999 and future Yuan / tonne.

TABLE 7.5: *Transportation Costs Uncertainties (Aggravated Transportation)*

Year	Inflation	Transp. Cost (no Infl.) Rail Δ%/yr	Transp. Cost (w/Infl.) Rail Δ%/yr	Transp. Cost (no Infl.) Ship Δ%/yr	Transp. Cost (w/Infl.) Ship Δ%/yr	Shanxi Rail/Ship Rail ¥/Tonne	Ship ¥/Tonne	Rail+Ship ¥/Tonne	Delivered Coal Cost Aggravated Transp. Case no Infl. ¥/Tonne	w/Infl. ¥/Tonne
1999						40.0	10.0	50.0	190.3	190.3
2000	0.0	0.0	0.0	1.0	1.0	40.0	10.1	50.1	190.4	190.4
2001	0.5	0.0	0.5	1.0	1.5	40.2	10.3	50.5	190.5	191.5
2002	1.0	0.0	1.0	1.0	2.0	40.6	10.5	51.1	190.6	193.5
2003	1.5	15.0	16.5	1.0	2.5	47.3	10.7	58.0	196.7	202.6
2004	2.0	15.0	17.0	1.0	3.0	55.3	11.0	66.4	203.7	213.8
2005	2.5	15.0	17.5	1.0	3.5	65.0	11.4	76.5	211.8	227.6
2006	3.0	0.0	3.0	1.0	4.0	67.0	11.9	78.9	211.9	234.5
2007	3.5	0.0	3.5	1.0	4.5	69.3	12.4	81.7	212.0	242.8
2008	4.0	0.0	4.0	1.0	5.0	72.1	13.0	85.1	212.1	252.7
2009	4.5	0.0	4.5	1.0	5.5	75.3	13.8	89.1	212.2	264.2
2010	5.0	0.0	5.0	1.0	6.0	79.1	14.6	93.7	212.3	277.5
2011	5.0	0.0	5.0	1.0	6.0	83.1	15.5	98.5	212.4	291.6
2012	5.0	0.0	5.0	1.0	6.0	87.2	16.4	103.6	212.5	306.3
2013	5.0	0.0	5.0	1.0	6.0	91.6	17.4	108.9	212.6	321.8
2014	5.0	0.0	5.0	1.0	6.0	96.2	18.4	114.6	212.7	338.0
2015	5.0	0.0	5.0	1.0	6.0	101.0	19.5	120.5	212.9	355.1
2016	5.0	10.0	15.0	1.0	6.0	116.1	20.7	136.8	219.1	383.2
2017	5.0	10.0	15.0	1.0	6.0	133.5	21.9	155.4	225.9	414.1
2018	5.0	10.0	15.0	1.0	6.0	153.6	23.2	176.8	233.4	448.4
2019	5.0	0.0	5.0	1.0	6.0	161.2	24.6	185.9	233.5	471.1
2020	5.0	0.0	5.0	1.0	6.0	169.3	26.1	195.4	233.6	494.9
2021	5.0	0.0	5.0	1.0	6.0	177.8	27.7	205.4	233.7	519.9
2022	5.0	0.0	5.0	1.0	6.0	186.6	29.3	216.0	233.8	546.1
2023	5.0	0.0	5.0	1.0	6.0	196.0	31.1	227.1	234.0	573.7
2024	5.0	0.0	5.0	1.0	6.0	205.8	33.0	238.7	234.1	602.7

FIGURE 7.3: *Price Trajectories of Raw and Various Delivered Coal for Shandong Utility (Market Stabilization Uncertainty)*

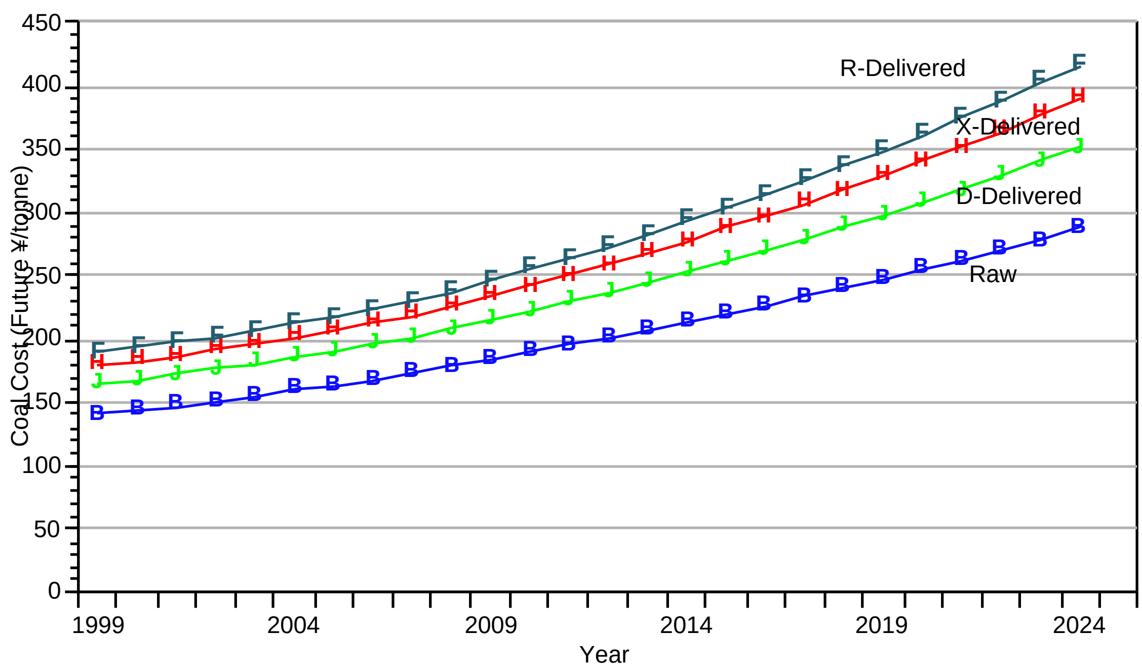


FIGURE 7.4: *Price Trajectories of Raw and Various Delivered Coal for Shandong Utility (Production Revolution Uncertainty)*

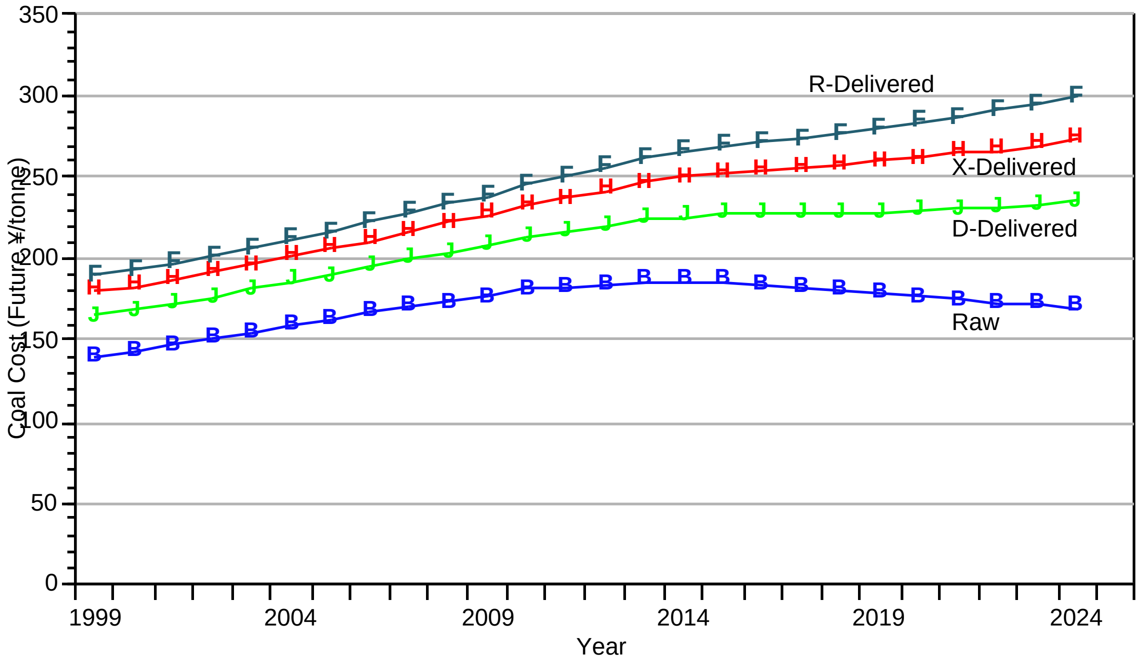
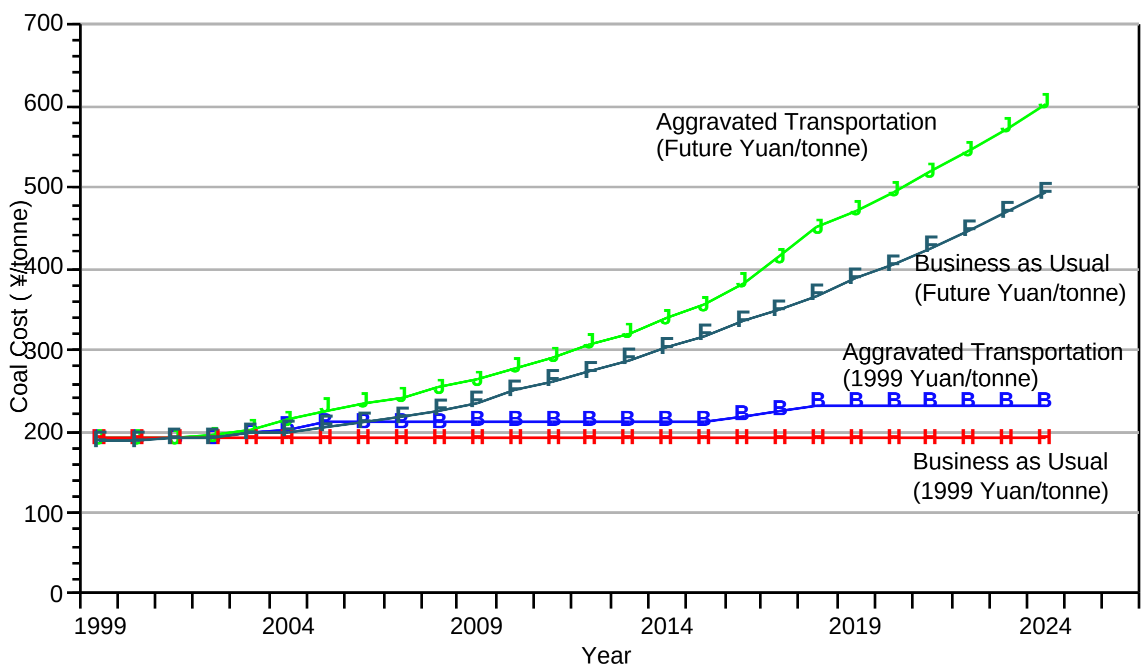


FIGURE 7.5: *Price Trajectories of Delivered Shanxi Coal for Shandong Utility (Aggravated Transportation vs. Business as Usual)*



Prepared by Chia-Chin Cheng with the assistance of Stephen Connors, Christopher Hansen and Jennifer Barker

CHAPTER 8: NON-COAL FUELS: CHARACTERISTICS AND COSTS

INTRODUCTION

The market for non-coal fuels in China is expected to increase dramatically over the next two decades as the need to diversify energy sources for pollution abatement and energy security increases in importance. This document describes the technical characteristics and cost assumptions used in electric sector simulation (ESS) scenarios for diesel, residual fuel oil, natural gas, and nuclear fuels.

We drew upon a variety of literature sources including recent reports on China energy futures, regional adjustment factors as well as correspondence with Chinese colleagues to arrive our fuel cost and characteristics assumptions. Monetary values are expressed in 1999 Yuan (¥) with a fixed exchange rate of ¥8 to $1 US.

Table 8.1 shows base cost and composition assumptions, and Table 8.2 displays our assumed cost escalation trajectories for the 2000–2024 study period. Information on renewable fuels is presented in the chapter "Future Alternate Fueled and Renewable Generation Characteristics and Costs."

TABLE 8.1: *Fuel Costs and Characteristics*

Fuel Type	Heating Value (LHV)	Base Year (1999) Fuel Cost		Total Sulfur	Total Carbon	Carbon Dioxide
Pipeline Natural Gas	48.84	26.00	3.25	0.00	73.00	54.8
Liquified Natural Gas	48.84	32.00	4.00	0.00	75.00	56.3
Diesel Fuel (Oil2)	44.51	60.00	7.50	0.50	87.00	71.7
Residual Oil (Oil6)	39.37	36.00	4.50	1.60	85.00	79.2
Nuclear Fuel 3.25%	2850000	4.80	0.60	0.00	0.00	0.0
Nuclear Fuel 8%	3880000	5.60	0.70	0.00	0.00	0.0
	(GJn/tonne)	(¥/GJnet)	($/GJnet)	(wgt.%S)	(wgt.%C)	(kg CO2/GJn)

PETROLEUM FUELS

The majority of petroleum based fuels in Shandong are imported and are used primarily for transportation and industrial processes. However, for power generation diversification and peak power production, two petroleum-based fuels are considered, diesel (Oil 2) and residual fuel oil (Oil 6). Diesel fuel has a lower specific gravity and fewer impurities compared to Oil 6, but diesel fuel is more expensive and thus will most likely be used for back up and peaking applications in Shandong. Oil 6 is a heavy grade of refined oil that remains after refining for gasoline and diesel. It is much cheaper than the more highly volatile fuels, but has a lower heat content and presents greater sulfur and ash pollution problems. As China is a net importer of oil, from an energy security and balance of payments point of view petroleum is not likely to be used on a large scale for baseload electricity production.

NATURAL GAS

Natural Gas consists of two main streams of supply, liquefied natural gas (LNG) and pipeline supply from gas fields. LNG or super-cooled natural gas, requires storage and receiving equipment to handle the ship-loaded delivery, which would represent a large capital investment for Shandong if it pursued LNG options. Due to these capital constraints, we include LNG in our data set, but do not use it in the current set of ESS scenarios. However, LNG costs do serve as a long run upper bound for pipeline gas prices even if no LNG investment is made in Shandong.

Expansion of pipeline gas supplies is a priority for the Chinese government. Recent natural gas discoveries and agreements to bring gas from Western China, Mongolia and Siberia to Eastern China have advanced this goal. In our scenarios we assume that gas from Bo Hai Bay may be used for peak load combustion turbines beginning in 2008, but will not be sufficient to support baseload power generation, which we assume will start in 2015 from pipeline gas supplies (Shan, 2000). The first users of pipeline gas, estimated to reach Shandong by 2012, will most likely be industrial plants in need of process heat and residential consumers for cooking and heating, thus our assumed lag for natural gas baseload power generation.

Natural gas has the advantage of lowering CO_2 emissions while increasing generating efficiency. However, its relatively high cost (base year set at ¥26 / Gj_{net}) compared to coal will likely limit its adoption until Shandong secures more reliable and cheaper supplies. Our cost trajectories assume that natural gas will rise at a rate of 1 percent over inflation after pipeline supplies become available due to spurred demand and an expected delivery infrastructure undercapacity during the last 10 years of the study period. However, prices may decline as transport technology improves and more pipeline capacity comes online. As an additional sensitivity / uncertainty, scenarios were also run with a base year cost of pipeline natural gas of ¥15 / Gj_{net}, with the same annual escalation factors as the reference trajectory.

NUCLEAR FUEL

Nuclear energy is an important option for Shandong energy planners to consider. The nuclear fuel supply can be divided into two types, 3.25% U-235 enriched for advanced light water reactors (ALWR) and 8.0% U-235 enriched for high temperature gas cooled reactors. China currently produces the light water fuel from domestic uranium ore. The international market is experiencing an oversupply of fuel and enrichment capacity, which should keep prices low throughout the study period (EIA, Uranium Report, 2000). 4.80 ¥ / GJ_{net} (\$0.60 / GJ_{net}) is a conservative U.S. estimate for 3.25%-enriched fuel (burnup approximately 33,000 kWd / kgU)[1] based on Energy Information Administration and Nukem Market report data.

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[1] Burnup is defined as kilowatt days produced per kilogram of uranium heavy metal in the fuel. Burnup accounts for energy produced from all fissionable products including plutonium produced by neutron absorption during operation minus the fissionable uranium that is not used during the fuel residency time in the reactor. ALWR (3.25% U-235) fuel will typically remain in the reactor until 0.9% fissionable uranium remains.

The more highly enriched, higher burnup (approximately 45,000 kWd / kgU), 8% U-235 fuel is not currently produced in quantity anywhere in the world. However, advanced design and fabrication work in South Africa and at MIT on a pebble bed Modular High Temperature Gas-Cooled Reactor (MHTGR), has estimated the price of fuel at mass production levels at less than $4 per MWh to $8.5 per MWh, respectively (Nicholls, 1998 and Kadak, 1998). The work by Kadak at MIT assumed $25 / LB U_3O_8 and $125 / kg-SWU, which is higher than EIA current prices or long term estimates. Domestic supply of this fuel should be possible in China if a large MHTGR program is undertaken, which will keep fuel costs low. The fuel itself is fabricated into spherical graphite elements approximately the size of tennis balls (60 mm in diameter) that contain 15,000 half mm uranium particles (Nukem, 2000). Each ball contains about 9 grams of 8% uranium and is sintered for high durability and temperature tolerance, estimated at above 1600° C (Nicholls, 1999).

FUEL COST ESCALATION TRAJECTORIES

We assume fuel costs change throughout the study period according to a set of uncertainty trajectories for each fuel. We model inflation as increasing by half a percentage point from 2000 to 2010, in 2011-2024 we then assume it to remain static at 5%. The current economic situation in China is one of slight deflation, but we assume a steady reversal toward low inflation levels. Table 8.2 delineates year by year inflation and price escalation uncertainties for each fuel.

TABLE 8.2: *Fuel Escalation Assumptions with Inflation (Δ% from previous year)*

Year	Inflation Rate	Pipeline Gas	Diesel Fuel 0.5% S	Residual Oil 1.6% S	Nuclear Fuel 3.25% U	Nuclear Fuel 8% U	Coal: Business As Usual	Coal: Production Innovation	Coal: Aggrevated Transport
1999							Shanxi Meager-Prepared (1-1.5% S)		
2000	0.00	0.00	0.50	0.50	0.00	0.00	0.00	1.58	0.00
2001	0.50	0.50	1.00	1.00	0.50	0.50	0.50	2.08	0.50
2002	1.00	1.00	1.50	1.50	1.00	1.00	1.00	2.59	0.99
2003	1.50	1.50	2.00	2.00	1.50	1.50	1.50	2.30	4.14
2004	2.00	2.00	2.50	2.50	2.00	2.00	2.00	2.80	4.91
2005	2.50	2.50	3.00	3.00	2.50	2.50	2.50	2.50	5.66
2006	3.00	3.00	3.50	3.50	3.00	3.00	3.00	2.20	2.91
2007	3.50	3.50	4.00	4.00	3.50	3.50	3.50	2.70	3.39
2008	4.00	5.00	4.50	4.50	4.00	4.00	4.00	2.40	3.85
2009	4.50	5.50	5.00	5.00	4.50	4.50	4.50	2.12	4.31
2010	5.00	6.00	5.50	5.50	5.00	5.00	5.00	2.63	4.75
2017	5.00	6.00	5.50	5.50	5.00	5.00	5.00	1.51	7.21
2024	5.00	6.00	5.50	5.50	5.00	5.00	5.00	1.03	4.77
	(Δ% / yr)	(Δ% / yr, w / inflation)					(Δ% / yr, w / inflation)		

We model pipeline natural gas, diesel and Oil 6 to experience slight real price increases within the study period. Petroleum prices will likely remain extremely volatile, and we stress all assumptions are modeled as price uncertainties rather than forecasts.

The escalation rates of fuel prices are then converted into cost in future Yuan as displayed in Table 8.3. Note that coal costs decline at varying rates depending on the uncertainty selected. Coal fuel is split into three escalation uncertainties: Business as Usual, Aggravated Transport and Production Innovation. The first assumes that no significant changes in mining technology or coal mine rationalization takes place. Thus, the price of coal remains static in real terms, rising at the rate of inflation over the 20 year study period. The Aggravated Transport uncertainty captures the cost increases that may be caused by rail transport bottlenecks. More coal demand, especially from Shanxi province to the northwest, means that an overstressed rail system may drive up the cost of coal. The Production Innovation uncertainty captures the effect of better mining techniques, which may depress coal prices because of increased production efficiency. In the last column, the effects of market stabilization are predicted. This future reflects the price reductions when subsidies are removed and prices are allowed to shift with market forces. For more information on coal costs uncertainties, see "Coal Cost Assumptions and Coal Cost Uncertainty Development".

TABLE 8.3: *Future Fuel Cost Assumptions and Uncertainties*

	Natural Gas		Oil		Nuclear		Coal			
	Base Case		Base Case		Base Case		Business As Usual	Aggravated Transport	Production Innovation	Market Stablization
YEAR	NGAS	LNG	DIES	O616	NUC3	NUC8	XR34(I)	XR34(A)	XR34(U)	XR 34 (O)
1999	**26.00**	**32.00**	**60.00**	**36.00**	**4.80**	**5.60**	**8.56**	**8.56**	**8.56**	**8.56**
2000	26.00	32.00	60.30	36.18	4.80	5.60	8.56	8.56	8.69	8.69
2001	26.13	32.16	60.90	36.54	4.82	5.63	8.60	8.60	8.88	8.88
2002	26.39	32.48	61.82	37.09	4.87	5.68	8.69	8.69	9.11	9.11
2003	26.79	32.97	63.05	37.83	4.95	5.77	8.82	9.06	9.32	9.32
2004	27.32	33.63	64.63	38.78	5.04	5.88	9.00	9.53	9.58	9.58
2005	28.01	34.47	66.57	39.94	5.17	6.03	9.22	10.10	9.82	9.82
2006	28.85	35.50	68.90	41.34	5.33	6.21	9.50	10.41	10.03	10.03
2007	29.86	36.75	71.65	42.99	5.51	6.43	9.83	10.77	10.30	10.30
2008	31.35	38.22	74.88	44.93	5.73	6.69	10.22	11.20	10.55	10.55
2009	33.07	39.94	78.62	47.17	5.99	6.99	10.68	11.71	10.77	10.77
2010	35.06	41.93	82.95	49.77	6.29	7.34	11.22	12.29	11.06	11.06
2011	37.16	44.03	87.51	52.51	6.60	7.70	11.78	12.91	11.26	11.26
2012	39.39	46.23	92.32	55.39	6.93	8.09	12.37	13.55	11.47	11.47
2013	41.75	48.54	97.40	58.44	7.28	8.49	12.98	14.23	11.69	11.69
2014	44.26	50.97	102.76	61.65	7.65	8.92	13.63	14.94	11.83	11.83
2015	46.91	53.52	108.41	65.04	8.03	9.37	14.32	15.69	11.98	11.98
2016	49.73	56.19	114.37	68.62	8.43	9.83	15.03	16.88	12.04	12.04
2017	52.71	59.00	120.66	72.40	8.85	10.33	15.78	18.19	12.11	12.11
2018	55.88	61.95	127.30	76.38	9.29	10.84	16.57	19.64	12.19	12.19
2019	59.23	65.05	134.30	80.58	9.76	11.38	17.40	20.62	12.28	12.28
2020	62.78	68.30	141.68	85.01	10.25	11.95	18.27	21.65	12.37	12.37
2021	66.55	71.72	149.48	89.69	10.76	12.55	19.18	22.73	12.48	12.48
2022	70.54	75.30	157.70	94.62	11.30	13.18	20.14	23.87	12.60	12.60
2023	74.77	79.07	166.37	99.82	11.86	13.84	21.15	25.07	12.73	12.73
2024	79.26	83.02	175.52	105.31	12.45	14.53	22.21	26.32	12.87	12.87
	Future (Nominal) ¥/Gjnet, includes inflation									

FIGURE 8.1: *Future Costs Trajectories of Shandong Fuels* (1999-2024)

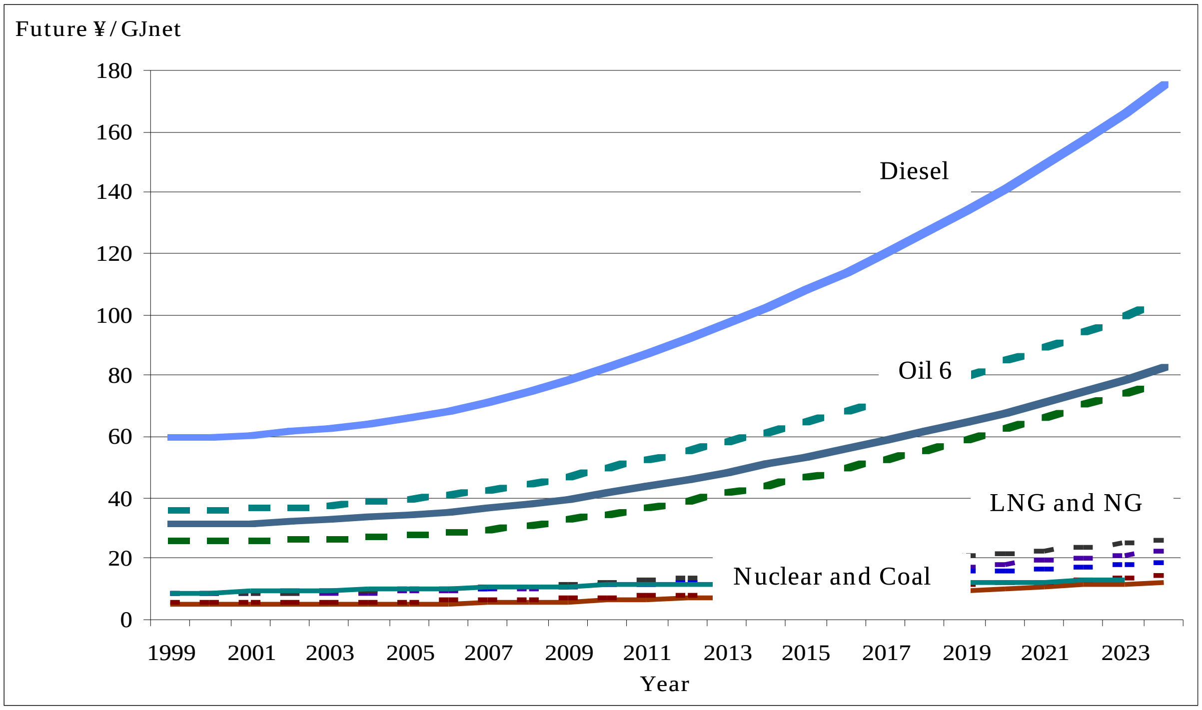
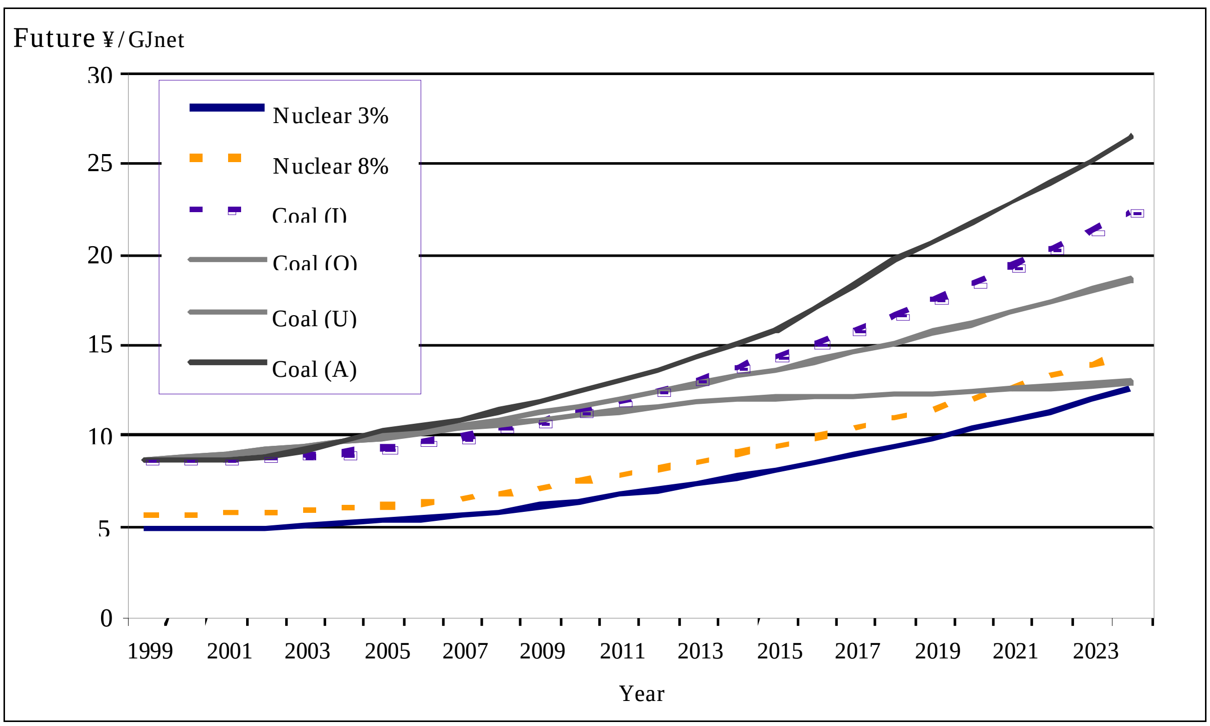


FIGURE 8.2: *Future Costs of Shandong Fuels, Nuclear and Coal* (1999-2024)



CONCLUSION

The diversification and stability of the Shandong power generation fuel supply is an important design criteria for planners. Relative costs of fuels can cause pronounced dispatch effects for new units, and may cause older, dirtier units to run more. Thus, environmental gains may be undercut by high fuel prices. The ESS analysis, shows that gas will have a difficult time replacing coal for baseload power unless prices remain low. Nuclear fuel costs are insignificant relative to the capital investment in the plants, but disposal costs may escalate if suitable repositories are not built.

Prepared by Christopher Hansen with the assistance of Stephen Connors, Chia-Chin Cheng and Jennifer Barker

CHAPTER 9: ELECTRICITY DEMAND AND END-USE EFFICIENCY ASSUMPTIONS AND UNCERTAINTIES

INTRODUCTION

Understanding electricity demand characteristics and modeling future demand growth is an essential task in any electricity planning exercise. Two electricity demand parameters are of major concern in our study: Annual Electricity Demand in GWh, which is the total electricity consumption in one year within a given service territory, and Annual Peak Load Demand in MW, which is the highest hourly electricity load experienced during the year. Mathematically, Annual Electricity Demand is expressed as the area under annual load-duration curve showing the distribution between base load and peak demands, and Annual Peak Load Demand is the point of maximum value on an annual load-duration curve. In order for electricity supply to meet both annual and peak-load demand, generation capacity must exceed the peak load demand in order to ensure high quality electricity service and smooth system operation.

This chapter explains the Electric Sector Simulation's approach to the development of electricity and peak load growth uncertainties for the Shandong scenarios, as the energy and load impacts of possible peak load management and electricity conservation programs.

MODELING LONG-TERM ELECTRICITY DEMAND GROWTH

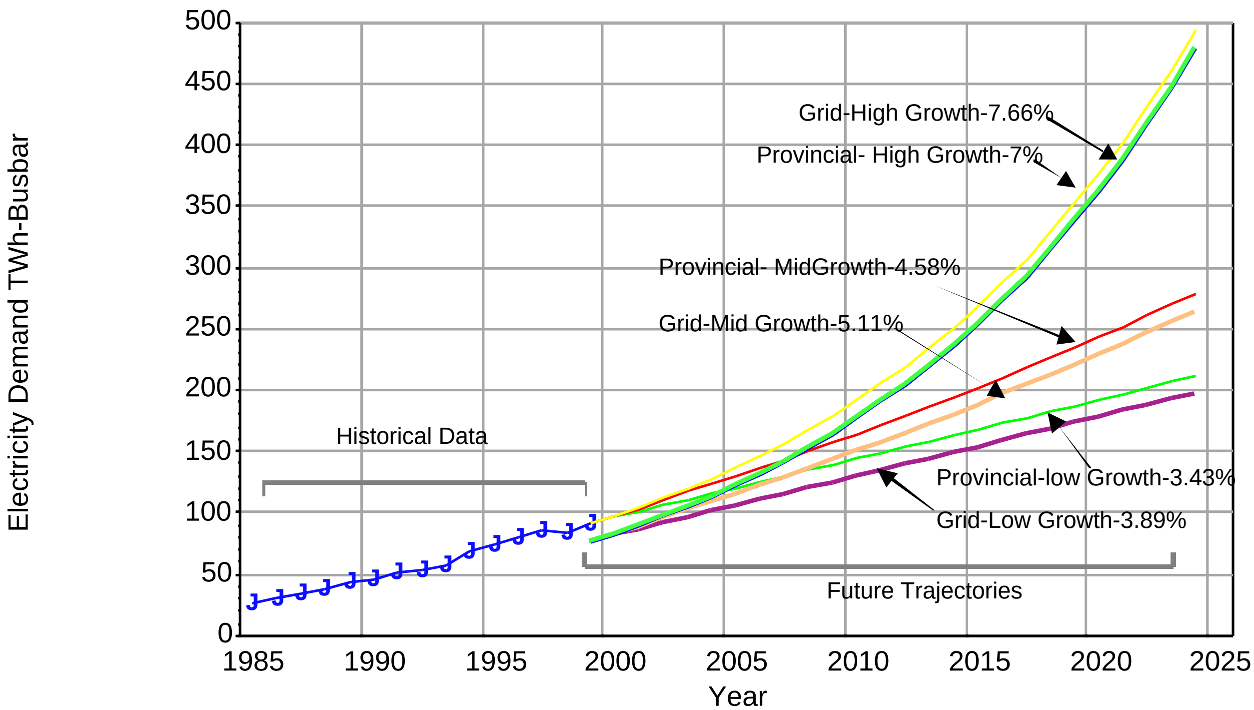
Smooth demand forecasts based on historical data are often wrong, as many unpredictable factors affect future electricity demand. For example, over the 25-year time frame of our simulation, economic and population growth change are likely to be the most important determinants of demand trajectories. Nevertheless, these factors are also likely to be endogenously influenced by unforeseeable policy choices and technological change, as well as fits and starts in the global economy.

Our study handles annual electricity demand growth as an uncertainty. We currently model three growth trajectories (for low, moderate, and strong growth) using a curve fitting method to represent *grid* demand at the busbar level. Busbar electricity output is measured right before electricity is sent out from a power plant. It presents the electricity consumption after discounting auxiliary power consumed for plant operation and before subtracting line loss from transmission and distribution process, which we consider to be more representative of real grid consumption in Shandong.

We were able to obtain hourly data for grid busbar generation from Shandong Electricity Power Research Institute (SEPRI) for 1998 and 1999, though two years is not sufficient for detailed demand modeling. We therefore used historical Shandong *provincial* electricity consumption data (including non-grid-dispatched demand) obtained from the Electricity Research Institute of State Development Planning Commission (ERI) as a basis for demand modeling. We curve fit the historical provincial data two ways: linear, polynomial (x^2), plus a flat 7% growth rate to generate three long-term electricity demand trajectories. We subtracted the difference between Shandong Provincial and Shandong Grid Busbar Demand (approximately 15000 GWh in 1998 and 1999) from the three trajectories and assigned the resulting trajectories as the Shandong grid electricity demand growth trajectories. The assumption behind this operation is that non-grid-connected demand remains the same during the study period (2000-2024). Since most of this generation is in the industrial sector where such demand is rather constant, if retiring and substitution rates remain balanced the fixed non-grid demand assumption may be reasonable.

The modeled trajectories result in a long-term annual growth rate of 3.89%, 5.12% and 7.65% for slow, moderate and strong growth respectively. Tables 9.1 and 9.2 summarize the long-term load growth uncertainties. The moderate growth rate of 5.12% is rather close to the medium demand forecast of a 5.04% long-term growth rate from ERI (2000).

FIGURE 9.1: *Shandong Provincial and Grid Demand Trajectories*
(GWh-Smooth)



Shandong has managed a high growth of 10 to 20% in GDP and 7.5 to 17.5% in electricity consumption annually in the past 20 years (Shandong Statistics Yearbook, 1998, ERI, 2000). Thus, the 7.66 % annual growth is not an unreasonable assumption if Shandong continues its high economic growth. Figure 9.1 plots the three modeled grid demand trajectories and the corresponding Shandong provincial electricity consumption trajectories. Historical demand is also shown. The modeled electricity demand trajectories (expressed as Shandong Grid Busbar Demand) and the provincial electricity demand trajectories are listed in Table 9.1.

TABLE 9.1: *Provincial Electricity Demand and Shandong Grid Busbar Demand Trajectories*

	Provincial Electricity Demand			Grid Demand-Busbar			Annual Grid Demand Change		
Year	Linear	AdjPX2	Seven	Linear	AdjPX2	Seven	Linear	AdjPX2	Seven
1999	90900	90900	90900	75682	75682	75682			
2000	95888	96576	97263	80888	81576	82263	6.9	7.8	8.7
2001	100700	102386	104071	85700	87386	89071	5.9	7.1	8.3
2002	105513	110819	111356	90513	95819	96356	5.6	9.7	8.2
2003	110325	117040	119151	95325	102040	104151	5.3	6.5	8.1
2004	115137	123395	127492	100137	108395	112492	5.0	6.2	8.0
2005	119949	129884	136416	104949	114884	121416	4.8	6.0	7.9
2006	124762	136507	145966	109762	121507	130966	4.6	5.8	7.9
2007	129574	143264	156183	114574	128264	141183	4.4	5.6	7.8
2008	134386	150156	167116	119386	135156	152116	4.2	5.4	7.7
2009	139198	157181	178814	124198	142181	163814	4.0	5.2	7.7
2010	144011	164341	191331	129011	149341	176331	3.9	5.0	7.6
2011	148823	171635	204724	133823	156635	189724	3.7	4.9	7.6
2012	153635	179063	219055	138635	164063	204055	3.6	4.7	7.6
2013	158447	186625	234389	143447	171625	219389	3.5	4.6	7.5
2014	163260	194322	250796	148260	179322	235796	3.4	4.5	7.5
2015	168072	202152	268352	153072	187152	253352	3.2	4.4	7.4
2016	172884	210117	287136	157884	195117	272136	3.1	4.3	7.4
2017	177696	218216	307236	162696	203216	292236	3.0	4.2	7.4
2018	182509	226449	328742	167509	211449	313742	3.0	4.1	7.4
2019	187321	234816	351754	172321	219816	336754	2.9	4.0	7.3
2020	192133	243317	376377	177133	228317	361377	2.8	3.9	7.3
2021	196946	251952	402724	181946	236952	387724	2.7	3.8	7.3
2022	201758	260722	430914	186758	245722	415914	2.6	3.7	7.3
2023	206570	269625	461078	191570	254625	446078	2.6	3.6	7.3
2024	211382	278663	493354	196382	263663	478354	2.5	3.5	7.2
	(GWh - Provincial)			(GWh - Grid, Busbar)			(Δ%/yr.)		
LTG(Δ%/yr)	3.43	4.58	7.00	3.89	5.12	7.65	3.89	5.13	7.65

Due to annual variation in weather and the economy, historically, electricity demand growth has never been smooth. Representing the noisiness in the future demand trajectory is important because this type of annual variation can hinder a planner's ability to see "real" developments, and thereby cause over- or under-planning. For example, a sudden increase in electricity demand for only one or two years can lead decision-makers to build more power plants than actually need in the long run to meet anticipated increase in demand. We model this variation by randomly assigning noise within plus and minus one standard deviation of the historical variations around the long-term historical growth rate. This realistic planning approach promotes a risk management versus an optimal planning mentality by the utility. Figure 9.2 captures the noisiness in the annual growth in historical data and our model. Figure 9.3 shows the smooth and noisy trajectories of electricity demand, and Table 9.3 lists the modeled uncertainties (trajectories).

TABLE 9.2: *Summary of Long-Term Load Growth Uncertainties*

		Load Growth Uncertainty		
		Slow Demand (Linear)	Moderate Demand (AdjPX2)	Strong Demand (Seven)
Electricity Demand Growth		*Shandong Province*		
GWh	Smooth	3.43	4.58	7.00
		Shandong Grid		
GWh	Noisy	3.89	5.11	7.66
	Smooth	3.89	5.12	7.65
Peak Load Growth		*Shandong Grid*		
MW (Sectoral)	Noisy	4.19	5.58	8.36
	Smooth	4.20	5.59	8.36
MW (Uniform)	Noisy	3.87	5.11	7.65
	Smooth	3.88	5.11	7.64
		(Long-Term Growth -Δ%/yr) (Busbar)		

FIGURE 9.2: *Noisy Electricity Annual Growth Rate, Historical and Modeled*

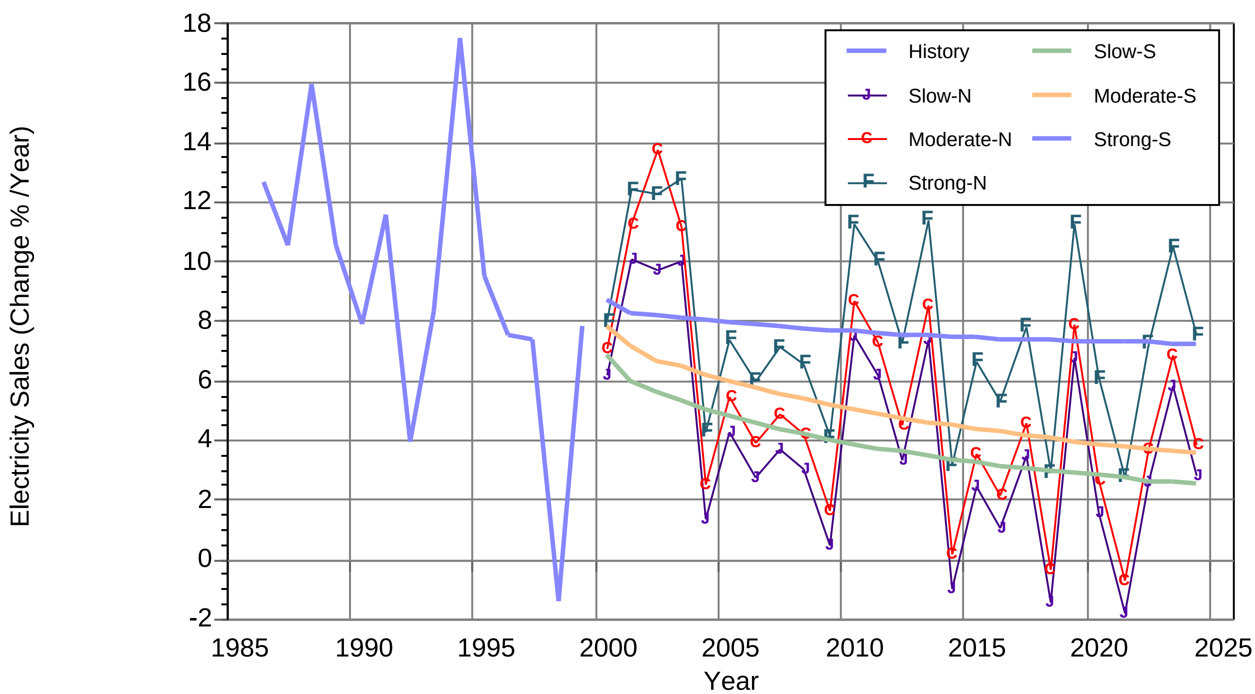
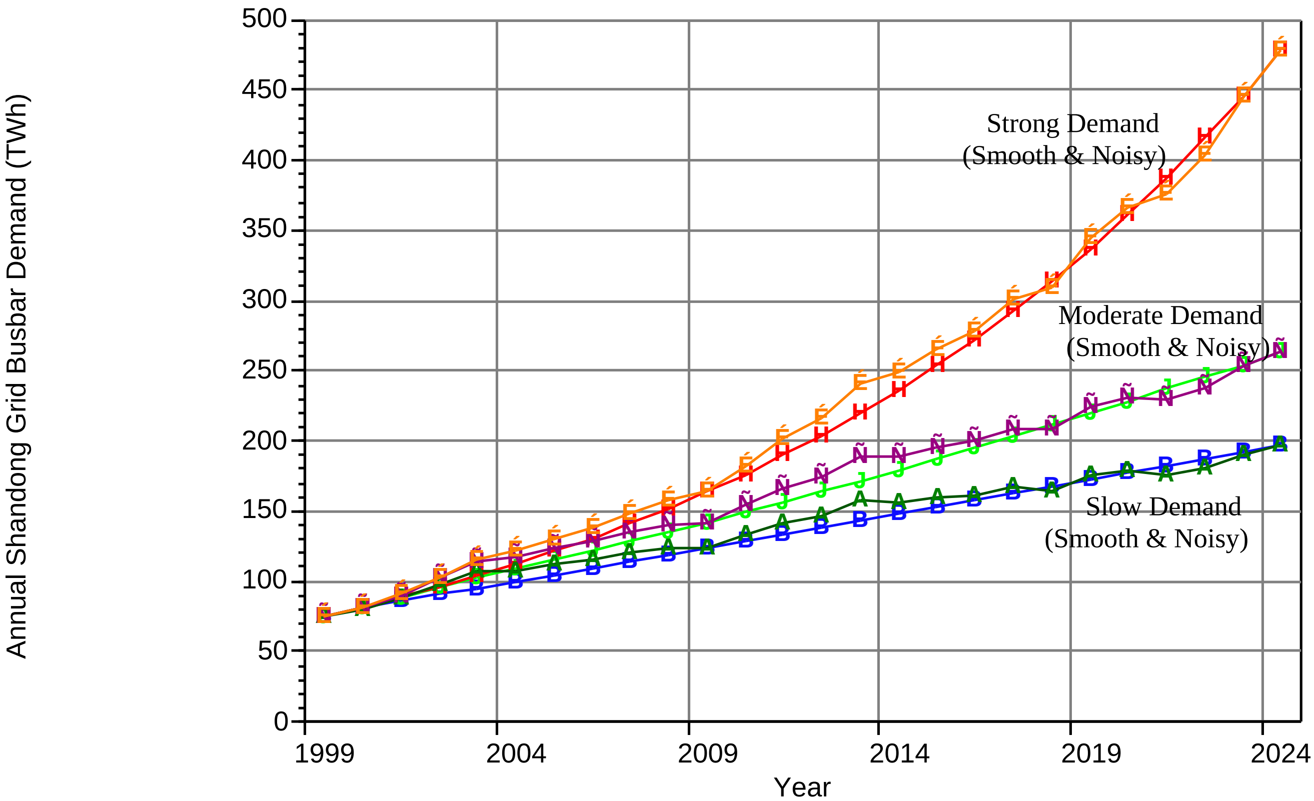


TABLE 9.3: *Smooth and Noisy Electricity Demand Uncertainties*

	Electricity Demand Growth - Shandong GRID / Busbar Generation									
	Slow	Moderate	Strong	Slow	Moderate	Strong	**Noisy**	Slow	Moderate	Strong
	Demand	Demand	Demand	Demand	Demand	Demand	**Growth**	Demand	Demand	Demand
Year	**Smooth**	**Smooth**	**Smooth**	**Noisy**	**Noisy**	**Noisy**	Unc.	**Noisy**	**Noisy**	**Noisy**
1999	75682	75682	75682	75682	75682	75682				
2000	80888	81576	82263	80373	81061	81748	-0.68	6.20	7.11	8.02
2001	85700	87386	89071	88482	90190	91899	4.14	10.09	11.26	12.42
2002	90513	95819	96356	97070	102583	103173	4.09	9.71	13.74	12.27
2003	95325	102040	104151	106783	114054	116359	4.69	10.01	11.18	12.78
2004	100137	108395	112492	108234	116949	121383	-3.69	1.36	2.54	4.32
2005	104949	114884	121416	112862	123330	130370	-0.53	4.28	5.46	7.40
2006	109762	121507	130966	115926	128134	138185	-1.87	2.72	3.90	5.99
2007	114574	128264	141183	120232	134401	148040	-0.67	3.71	4.89	7.13
2008	119386	135156	152116	123911	140090	157816	-1.14	3.06	4.23	6.60
2009	124198	142181	163814	124507	142399	164350	-3.55	0.48	1.65	4.14
2010	129011	149341	176331	133863	154753	182891	3.64	7.51	8.68	11.28
2011	133823	156635	189724	142123	166087	201245	2.44	6.17	7.32	10.04
2012	138635	164063	204055	146864	173532	215922	-0.26	3.34	4.48	7.29
2013	143447	171625	219389	157734	188350	240634	3.93	7.40	8.54	11.44
2014	148260	179322	235796	156211	188660	248234	-4.32	-0.97	0.16	3.16
2015	153072	187152	253352	160063	195427	264780	-0.78	2.47	3.59	6.67
2016	157884	195117	272136	161734	199640	278851	-2.10	1.04	2.16	5.31
2017	162696	203216	292236	167359	208785	300646	0.43	3.48	4.58	7.82
2018	167509	211449	313742	164962	208077	309573	-4.39	-1.43	-0.34	2.97
2019	172321	219816	336754	176200	224509	344476	3.94	6.81	7.90	11.27
2020	177133	228317	361377	179007	230498	365530	-1.20	1.59	2.67	6.11
2021	181946	236952	387724	175797	228821	375694	-4.51	-1.79	-0.73	2.78
2022	186758	245722	415914	180394	237220	402897	-0.03	2.61	3.67	7.24
2023	191570	254625	446078	190941	253573	445292	3.27	5.85	6.89	10.52
2024	196382	263663	478354	196291	263309	478802	0.29	2.80	3.84	7.53
	(GWh-Grid, Busbar)			(GWh-Grid, Busbar)			(+Δ% / yr)	(Δ% / yr-Noisy)		
LT-Gr.	3.89	5.12	7.65	3.89	5.11	7.66				
	(Δ% / yr)			(Δ% / yr)						

FIGURE 9.3: *Smooth and Noisy Electricity Demand Uncertainties*



MODELING PEAK-LOAD DEMAND GROWTH

As with historical annual electricity demand data, we found limited historical peak load data for Shandong. Nevertheless, peak load demand is one of the most important pieces of information for capacity planning. We developed a method to generate peak load trajectories by introducing peak load multipliers by consumer (sectoral) class: industrial, construction, transportation, agricultural, service and household. The multiplier is the inverse of the load factor and is defined as annual peak load divided by average annual hourly load. We derive the sectoral breakdowns of electricity demand from the ERI forecast, convert the sectoral electricity demand into average hourly load, and apply the sectoral load multipliers to the resulting sectoral average hourly load. The contribution of each sector to peak load is then aggregated to represent the modeled peak load trajectories.

We use two scenarios in constructing peak load trajectories: differential sectoral peak load growth and uniform peak load growth. In the first case, which is more reflective of reality in an economy, as it assumes differential peak load growth in different sectors. In this instance we apply different sectoral peak load multipliers to various sectors in the economy (see Table 9.4). In accordance with how Shandong's economy is evolving, we assume rapid load growth in service and household sectors, slightly slower growth in industry, and generally consistent growth in other sectors. Since the household and services sectors are important contributors to the current peak load hours (7:00-9:00 in the evening), higher load growth in these sectors due to increasing use of lighting and electrical appliances should result in an increasing peak load demand in the future. This "business as usual" peak load growth scenario represents a situation where peak load grows faster than electricity demand does. Increasing peak load demand in Shandong could therefore result in higher overall demand for power generating capacity.

In the second case, which results in the "peak management" scenario, we assume uniform sectoral load multipliers across all sectors. This approach implies that load growth in all sectors in the economy follows the same pace. Consequently, future peak load demand and the electricity demand will generally grow at the same rate. Given Shandong's current peak load situation, we believe this scenario could only happen if certain peak management measures are taken to prevent rapid peak load growth.

TABLE 9.4: *Sectoral Load Multipliers*

	Industrial	Cons-truction	Trans-portation	Agri-cutural	Service	Household
Sectoral Multipliers	1.30	1.50	1.50	1.45	3.00	**3.00**
Uniform Multipliers	1.45	1.45	1.45	1.45	1.45	1.45

As with the electricity demand trajectories, we also apply noisiness to peak load demand trajectories. Starting with a smooth peak load trajectory, we applied noise to the peak load contribution of each sector, and then deriving an aggregated noisy trajectory of peak load demand. We considered three electricity demand growth uncertainties with respect to the trajectories of peak load construction.

The modeled peak load demand trajectories are summarized in Figure 9.4. The "business as usual " and "peak management " peak load trajectories are listed in Table 9.5 and 9.6 respectively.

MODELING END-USE EFFICIENCY

End-use efficiency is an important part of electricity demand side management. To supplement the "peak management" approach described above, an end-use efficiency program implemented in Shandong could reduce both electricity demand and peak load demand growth. Our initial scenario set incorporates three end-use efficiency scenarios to model the potential effects of end-use efficiency programs: Current Standards (baseline), Moderate and Aggressive demand-side management (DSM) efforts.

FIGURE 9.4: *Peak Load Demand Uncertainties*

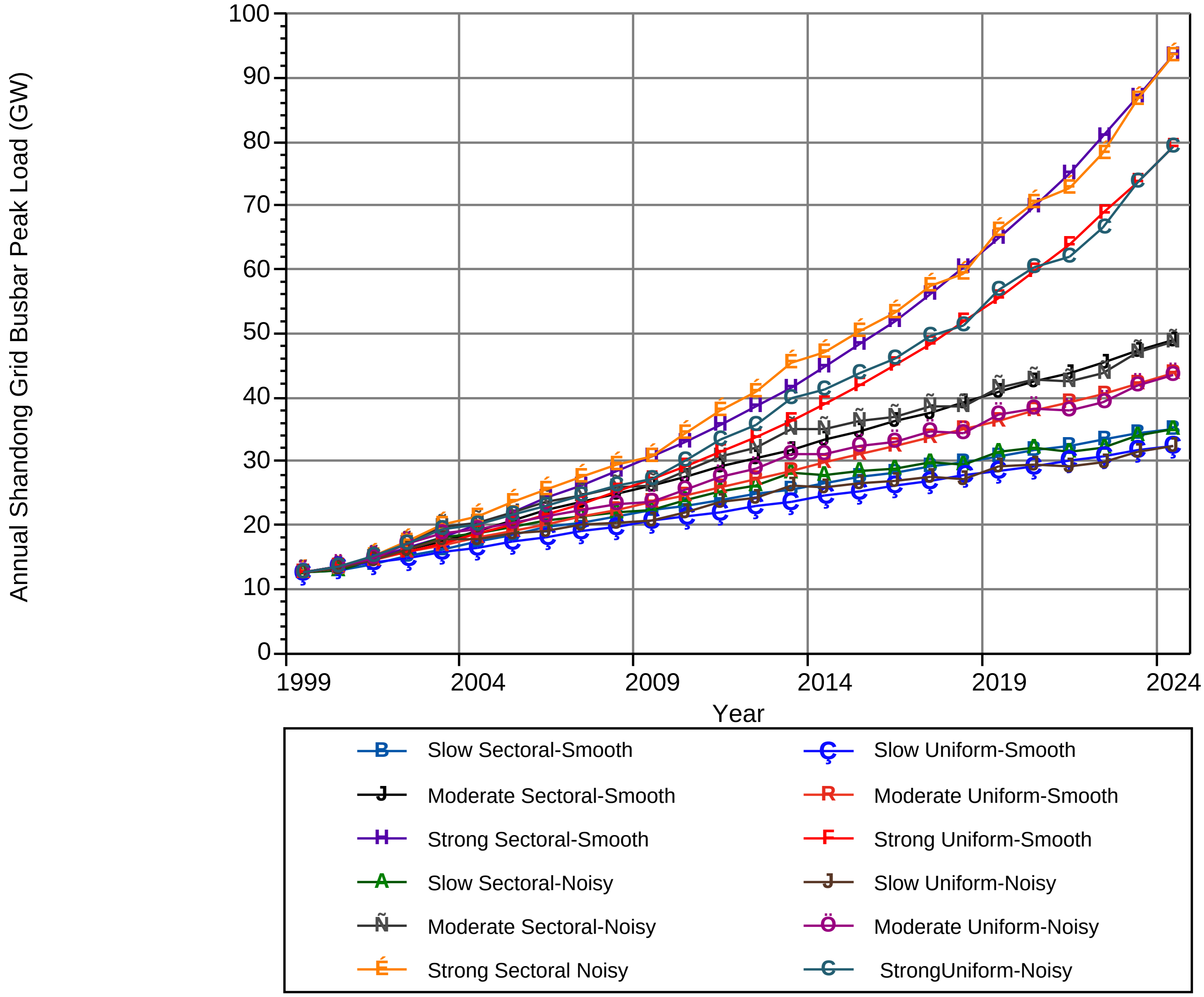


TABLE 9.5: *Peak Load Trajectories in "Business As Usual" Scenario (Sectoral – No Peak Load Management)*

	Peak Load Growth / Sectoral - Shandong GRID / Busbar Annual Peak Load									
Year	Slow Demand **Smooth**	Moderate Demand **Smooth**	Strong Demand **Smooth**	Slow Demand **Noisy**	Moderate Demand **Noisy**	Strong Demand **Noisy**	**Noisy Growth** Unc.	Slow Demand **Noisy**	Moderate Demand **Noisy**	Strong Demand **Noisy**
1999	12548	12548	12548	12548	12548	12548				
2000	12990	13188	13299	12904	13102	13213	-0.68	2.84	4.42	5.30
2001	14022	14430	14730	14464	14879	15183	4.14	12.09	13.56	14.91
2002	15083	16160	16304	16150	17271	17426	4.09	11.66	16.08	14.77
2003	16173	17574	18034	18075	19593	20092	4.69	11.92	13.44	15.30
2004	17293	19062	19935	18659	20529	21469	-3.69	3.23	4.78	6.85
2005	18441	20628	22023	19799	22106	23604	-0.53	6.11	7.68	9.95
2006	19619	22306	24315	20693	23492	25618	-1.87	4.52	6.27	8.53
2007	20479	23598	26283	21462	24695	27520	-0.67	3.71	5.12	7.42
2008	21339	24921	28395	22119	25797	29418	-1.14	3.06	4.46	6.90
2009	22199	26273	30661	22225	26281	30721	-3.55	0.48	1.88	4.43
2010	23059	27656	33092	23895	28622	34276	3.64	7.51	8.90	11.57
2011	23919	29018	35723	25370	30729	37837	2.44	6.17	7.36	10.39
2012	24779	30405	38548	26216	32119	40731	-0.26	3.34	4.52	7.65
2013	25640	31819	41580	28156	34874	45535	3.93	7.40	8.58	11.80
2014	26500	33258	44836	27884	34945	47133	-4.32	-0.97	0.20	3.51
2015	27360	34724	48331	28572	36212	50440	-0.78	2.47	3.63	7.01
2016	28220	36194	52027	28870	36985	53238	-2.10	1.04	2.14	5.55
2017	29080	37690	55991	29874	38672	57523	0.43	3.48	4.56	8.05
2018	29940	39209	60241	29447	38534	59365	-4.39	-1.43	-0.36	3.20
2019	30800	40753	64799	31453	41569	66195	3.94	6.81	7.88	11.51
2020	31661	42321	69687	31954	42670	70394	-1.20	1.59	2.65	6.34
2021	32521	43922	75015	31381	42360	72602	-4.51	-1.79	-0.73	3.14
2022	33381	45549	80735	32201	43916	78116	-0.03	2.61	3.67	7.60
2023	34241	47200	86876	34084	46944	86612	3.27	5.85	6.90	10.88
2024	35101	48876	93467	35039	48747	93434	0.29	2.80	3.84	7.88
	(MW-Grid, Busbar)			(MW-Grid, Busbar)			(+Δ% / yr)	(Δ% / yr-Noisy)		
LT-Gr.	4.20	5.59	8.36	4.19	5.58	8.36				
	(Δ% / yr)			(Δ% / yr)						

Table 9.6: *Peak Load Trajectories in "Peak Management" Scenario (Uniform – Peak Load Management)*

	Peak Load Growth / Uniform - Shandong GRID / Busbar Annual Peak Load									
Year	Slow Demand **Smooth**	Moderate Demand **Smooth**	Strong Demand **Smooth**	Slow Demand **Noisy**	Moderate Demand **Noisy**	Strong Demand **Noisy**	**Noisy Growth** Unc.	Slow Demand **Noisy**	Moderate Demand **Noisy**	Strong Demand **Noisy**
1999	12548	12548	12548	12548	12548	12548				
2000	13376	13503	13617	13290	13417	13531	-0.68	5.92	6.93	7.84
2001	14171	14465	14741	14631	14929	15208	4.14	10.09	11.26	12.39
2002	14967	15860	15943	16051	16980	17071	4.09	9.71	13.74	12.25
2003	15763	16890	17229	17657	18879	19249	4.69	10.01	11.18	12.76
2004	16559	17942	18605	17897	19358	20076	-3.69	1.36	2.54	4.30
2005	17354	19016	20077	18662	20414	21558	-0.53	4.28	5.46	7.38
2006	18150	20112	21656	19169	21209	22850	-1.87	2.72	3.90	5.99
2007	18946	21231	23346	19881	22247	24480	-0.67	3.71	4.89	7.13
2008	19742	22372	25154	20490	23188	26097	-1.14	3.06	4.23	6.60
2009	20537	23535	27088	20588	23570	27177	-3.55	0.48	1.65	4.14
2010	21333	24720	29158	22135	25615	30243	3.64	7.51	8.68	11.28
2011	22129	25927	31379	23501	27491	33284	2.44	6.17	7.32	10.06
2012	22925	27157	33756	24285	28724	35719	-0.26	3.34	4.48	7.31
2013	23720	28408	36300	26082	31176	39815	3.93	7.40	8.54	11.47
2014	24516	29682	39022	25831	31228	41081	-4.32	-0.97	0.16	3.18
2015	25312	30978	41936	26467	32348	43828	-0.78	2.47	3.59	6.69
2016	26108	32297	45018	26744	33045	46129	-2.10	1.04	2.16	5.25
2017	26903	33637	48314	27674	34559	49704	0.43	3.48	4.58	7.75
2018	27699	35000	51839	27278	34442	51148	-4.39	-1.43	-0.34	2.90
2019	28495	36385	55608	29136	37162	56882	3.94	6.81	7.90	11.21
2020	29291	37792	59638	29600	38153	60322	-1.20	1.59	2.67	6.05
2021	30086	39222	64024	29069	37875	62038	-4.51	-1.79	-0.73	2.85
2022	30882	40673	68720	29829	39266	66570	-0.03	2.61	3.67	7.31
2023	31678	42147	73749	31573	41972	73618	3.27	5.85	6.89	10.59
2024	32474	43643	79132	32458	43584	79205	0.29	2.80	3.84	7.59
	(MW-Grid, Busbar)			(MW-Grid, Busbar)			(+Δ% / yr)	(Δ% / yr-Noisy)		
LT-Gr.	3.88	5.11	7.64	3.87	5.11	7.65				
	(Δ% / yr)			(Δ% / yr)						

In the baseline case, both electricity demand and peak load demand modeled above remain unchanged. In the moderate and aggressive end-use effort scenarios, we assume end-use efficiency programs are implemented to reduce the demand growth in the industrial, service and household sectors. Various percentage electrical energy savings on target end-use sectors are introduced over time. A cumulative 10% reduction in 25 year electricity demand is *assumed* for the moderate DSM case (across all three economic growth and two peak load management occurrences). The Aggressive DSM case *assumes* a cumulative 20% reduction. The percentage savings applied to each end-use sector (relative to the no DSM "Current Standards" case) for the moderate and aggressive end-use efficiency options are listed in Tables 9.7 and 9.8. Therefore, each end-use efficiency case results in six end-use efficiency trajectories, a total of eighteen demand side management trajectories are analyzed in our simulation.

Table 9.9 summarizes the example with three end-use efficiency scenarios under strong demand growth (7%) and business as usual (no peak load management) peak load growth. The electricity demand trajectories and peak load trajectories of the this case are graphed in Figures 9.5 and 9.6.

Note that we have very limited information to reasonably describe the potential of DSM programs in Shandong. Nor do we have sufficient data to estimate the costs of DSM programs in the initial study period of ESS. The 10 % and 20 % reduction are illustrative of the cost and emission reductions that are possible with such energy savings. The Laurence Berkley National Laboratory (LBNL) estimated that, in developing countries, promoting end-use efficiency programs could reduce the total energy investments by 40% within the next 30 years (Yang & Lau, 1999). Our assumption of energy reduction may not be unreasonable target to achieve in Shandong.

According to Yang & Lau, (1999), a DSM program in Shenjun, Guangdong are estimated to cost $41 million in total in 2000 and $14.6 / kW-year on average. In our initial study, we assume that the average cost of end-use efficiency programs in Shandong Province to be constant at $15 / kW-year. However, costs of DSM programs could vary widely with the types of measures and technologies implemented and with different electricity end-use structure. In addition, constant average cost over time may not be realistic since the cost may vary due to many factors such as technology deployment and easiness of penetration. A more detailed study on the energy savings and program costs will be performed in our later research.

TABLE 9.7: *Sectoral Electric Energy Savings in Moderate End-Use Efficiency Option* *(10% Cumulative Reduction)*

Year	Sectoral Energy Savings - Percent from Ref.						Total Change from Ref.
	Ind.	Constr.	Transp.	Agr.	Serv.	Hshld.	
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	1.0	0.0	0.0	0.0	0.0	0.0	0.8
2002	2.0	0.0	0.0	0.0	0.0	0.0	1.6
2003	3.0	0.0	0.0	0.0	0.0	0.0	2.3
2004	4.0	0.0	0.0	0.0	0.0	0.0	3.1
2005	5.0	0.0	0.0	0.0	1.0	1.0	4.0
2006	6.0	0.0	0.0	0.0	2.0	2.0	4.9
2007	7.0	0.0	0.0	0.0	3.0	3.0	5.9
2008	8.0	0.0	0.0	0.0	4.0	4.0	6.8
2009	9.0	0.0	0.0	0.0	5.0	5.0	7.7
2010	10.0	0.0	0.0	0.0	6.0	6.0	8.6
2011	11.0	0.0	0.0	0.0	7.0	7.0	9.5
2012	12.0	0.0	0.0	0.0	8.0	8.0	10.4
2013	13.0	0.0	0.0	0.0	9.0	9.0	11.3
2014	14.0	0.0	0.0	0.0	10.0	10.0	12.2
2015	15.0	0.0	0.0	0.0	10.0	10.0	12.9
2016	15.0	0.0	0.0	0.0	10.0	10.0	12.9
2017	15.0	0.0	0.0	0.0	10.0	10.0	13.0
2018	15.0	0.0	0.0	0.0	10.0	10.0	13.0
2019	15.0	0.0	0.0	0.0	10.0	10.0	13.1
2020	15.0	0.0	0.0	0.0	10.0	10.0	13.1
2021	15.0	0.0	0.0	0.0	10.0	10.0	13.0
2022	15.0	0.0	0.0	0.0	10.0	10.0	13.0
2023	15.0	0.0	0.0	0.0	10.0	10.0	12.9
2024	15.0	0.0	0.0	0.0	10.0	10.0	12.8
						LGT (Δ% / yr)	**10.6**

TABLE 9.8: *Sectoral Electric Energy Savings in Aggressive End-Use Efficiency Option* *(20% Cumulative Reduction)*

Year	Ind.	Constr.	Transp.	Agr.	Serv.	Hshld.	Total Change from Ref.
	Sectoral Energy Savings - Percent from Ref.						
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2000	2.0	0.0	0.0	0.0	1.0	1.0	1.8
2001	4.0	0.0	0.0	0.0	2.0	2.0	3.5
2002	6.0	0.0	0.0	0.0	3.0	3.0	5.2
2003	8.0	0.0	0.0	0.0	4.0	4.0	7.0
2004	10.0	0.0	0.0	0.0	5.0	5.0	8.7
2005	12.0	0.0	0.0	0.0	6.0	6.0	10.4
2006	14.0	0.0	0.0	0.0	7.0	7.0	12.1
2007	16.0	0.0	0.0	0.0	8.0	8.0	13.8
2008	18.0	0.0	0.0	0.0	9.0	9.0	15.5
2009	20.0	0.0	0.0	0.0	10.0	10.0	17.3
2010	22.0	0.0	0.0	0.0	11.0	11.0	19.0
2011	24.0	0.0	0.0	0.0	12.0	12.0	20.7
2012	26.0	0.0	0.0	0.0	13.0	13.0	22.4
2013	28.0	0.0	0.0	0.0	14.0	14.0	24.1
2014	30.0	0.0	0.0	0.0	15.0	15.0	25.8
2015	30.0	0.0	0.0	0.0	16.0	16.0	26.0
2016	30.0	0.0	0.0	0.0	17.0	17.0	26.1
2017	30.0	0.0	0.0	0.0	18.0	18.0	26.3
2018	30.0	0.0	0.0	0.0	19.0	19.0	26.4
2019	30.0	0.0	0.0	0.0	20.0	20.0	26.6
2020	30.0	0.0	0.0	0.0	20.0	20.0	26.6
2021	30.0	0.0	0.0	0.0	20.0	20.0	26.6
2022	30.0	0.0	0.0	0.0	20.0	20.0	26.6
2023	30.0	0.0	0.0	0.0	20.0	20.0	26.6
2024	30.0	0.0	0.0	0.0	20.0	20.0	26.6
						LGT (Δ% / yr)	**20.4**

TABLE 9.9: *Case With Three End-Use Efficiency Scenarios and Strong Economic Growth and Business As Usual Peak Demand Growth*

	Basline Scenario				**Moderate End-use Efficiency**				**Aggressive End-use Efficiency**			
	Efficiency Demand **Noisy**	Efficiency Peak **Noisy**	Efficiency Demand **Noisy**	Efficiency Peak **Noisy**	Efficiency Demand **Noisy**	Efficiency Peak **Noisy**	Efficiency Demand **Noisy**	Efficiency Peak **Noisy**	Efficiency Demand **Noisy**	Efficiency Peak **Noisy**	Efficiency Demand **Noisy**	Efficiency Peak **Noisy**
1999	75667	12475			75667	12475			75667	12475		
2000	81704	13208	7.98	5.88	81704	13208	7.98	5.88	80315	12992	6.14	4.15
2001	92740	15340	13.51	16.14	92034	15235	12.64	15.35	89594	14844	11.55	14.25
2002	100257	16971	8.11	10.63	98736	16746	7.28	9.91	95166	16156	6.22	8.84
2003	108971	18880	8.69	11.25	106502	18514	7.86	10.56	101609	17684	6.77	9.46
2004	108254	19199	-0.66	1.69	104998	18716	-1.41	1.09	99132	17695	-2.44	0.06
2005	120652	21907	11.45	14.10	115913	21165	10.40	13.08	108478	19869	9.43	12.28
2006	128388	23860	6.41	8.92	122161	22843	5.39	7.93	113298	21295	4.44	7.18
2007	140097	26107	9.12	9.42	132009	24752	8.06	8.36	121307	22906	7.07	7.57
2008	150231	28071	7.23	7.52	140173	26354	6.18	6.47	127599	24209	5.19	5.68
2009	157841	29572	5.06	5.35	145816	27490	4.03	4.31	131461	25061	3.03	3.52
2010	182567	34297	15.67	15.98	166975	31564	14.51	14.82	149056	28555	13.38	13.94
2011	194198	36595	6.37	6.70	175832	33341	5.30	5.63	155399	29932	4.26	4.82
2012	203402	38448	4.74	5.06	182302	34675	3.68	4.00	159476	30887	2.62	3.19
2013	227920	43214	12.05	12.40	202190	38576	10.91	11.25	175032	34090	9.75	10.37
2014	225564	42899	-1.03	-0.73	198038	37899	-2.05	-1.75	169611	33223	-3.10	-2.54
2015	251376	47954	11.44	11.78	218936	42105	10.55	11.10	188627	36987	11.21	11.33
2016	266262	50934	5.92	6.22	231939	44731	5.94	6.24	199331	39115	5.67	5.75
2017	293140	56231	10.09	10.40	255394	49393	10.11	10.42	218923	42991	9.83	9.91
2018	299429	57596	2.15	2.43	260916	50602	2.16	2.45	223062	43832	1.89	1.96
2019	349182	67352	16.62	16.94	304320	59184	16.64	16.96	259458	51015	16.32	16.39
2020	355969	68851	1.94	2.22	310286	60512	1.96	2.24	264603	52174	1.98	2.27
2021	369349	71632	3.76	4.04	322017	62971	3.78	4.06	274686	54310	3.81	4.10
2022	415041	80711	12.37	12.67	361932	70969	12.40	12.70	308823	61227	12.43	12.73
2023	460112	89717	10.86	11.16	401322	78905	10.88	11.18	342532	68094	10.92	11.22
2024	479453	93738	4.20	4.48	418281	82461	4.23	4.51	357109	71184	4.26	4.54
	(GWh - Grid, Busbar)		(Δ%/yr.)		(MW - Grid, Busbar)		(Δ%/yr.)		(MW - Grid, Busbar)		(Δ%/yr.)	
	7.66	8.40	7.76	8.51	7.08	7.95	7.18	7.95	6.40	7.21	6.51	7.32
	(Long-Term Growth –Δ%/yr)				(Long-Term Growth –Δ%/yr)				(Long-Term Growth –Δ%/yr)			

FIGURE 9.5: *Business As Usual Electricity Demand Trajectories with Three End-Use Efficiency Scenarios under Strong Economic Growth*

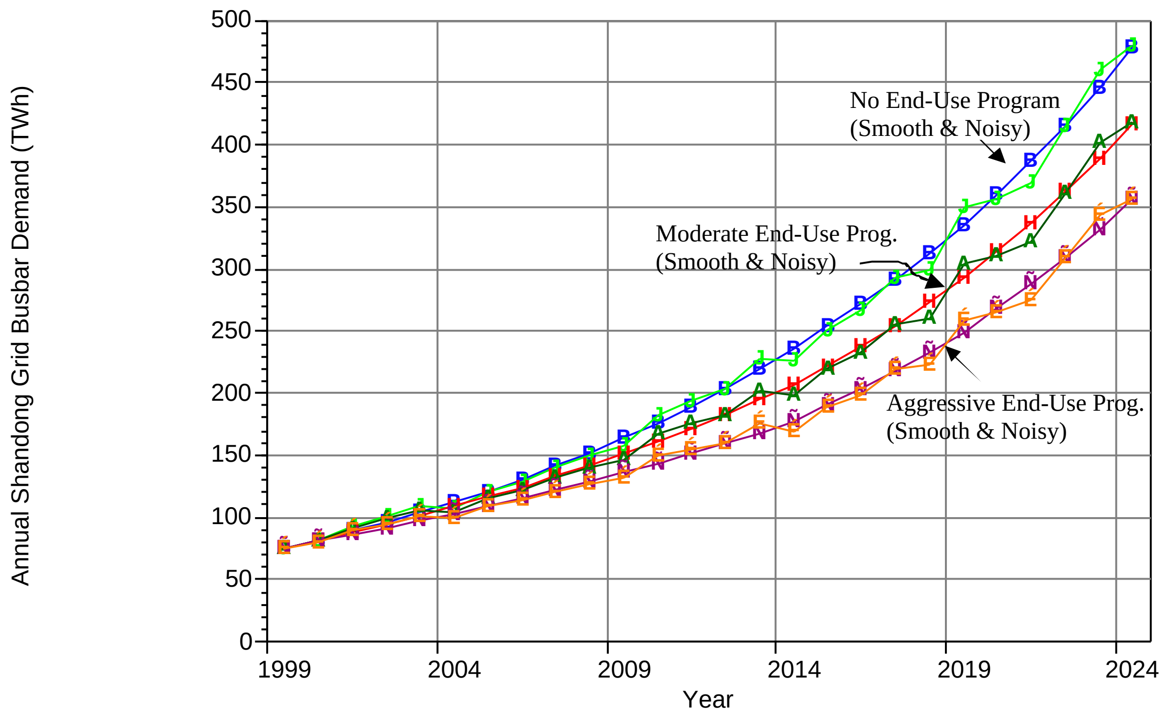
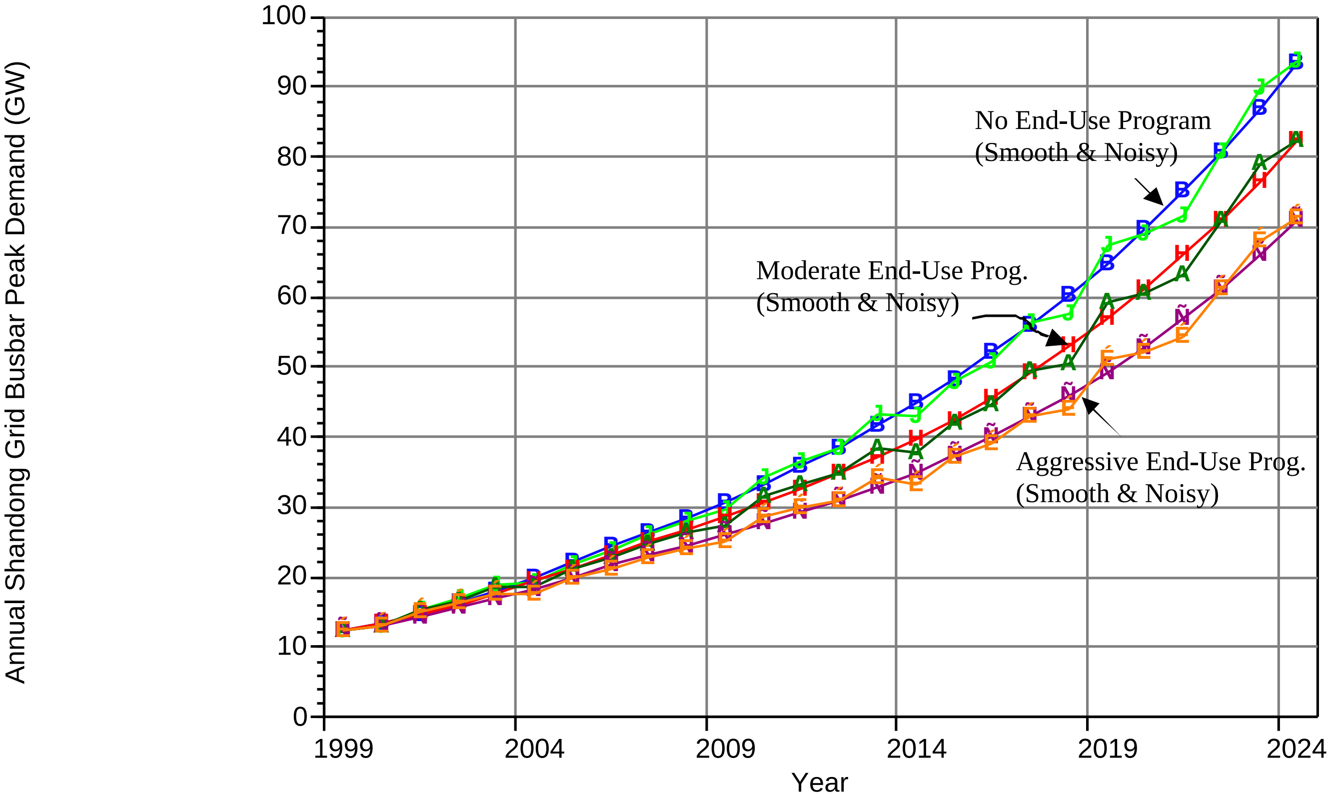


FIGURE 9.6: *Business As Usual Electricity Peak Load Trajectories with Three End-Use Efficiency Scenarios At Strong Economic Growth*



Prepared by Chia-Chin Cheng with the assistance of Stephen Connors, Christopher Hansen and Jennifer Barker

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Appendix A: Generation Technology Characteristics and Costs

Appendix A presents the detailed assumptions for the technologies described in Chapters 2 and 3. Below is the list of tables and some of the abbreviations.

Technology Type:

Adv_CT	=	Advanced Combustion Turbine (Simple Cycle, Steam Injection)
Adv_CC	=	Advanced Combined Cycle
PCoal	=	Pulverized Coal (Subcritical)
AFB	=	Atmospheric Fluidized Bed Combustion
IGCC	=	Integrated Gasification Combined Cycle
MHTGR	=	Modular High Temperature Gas Reactor (Pebble-Bed Reactor)
ALWR	=	Advanced Light Water Reactor

Table A-1: Generation Technology Basic Configurations

Cooling Water Method:

OC	=	Once through cooling	DC	=	Dry cooling
WC	=	Wet cooling	CL	=	Closed loop

Sulfur Removal Method:

WS	=	Wet scrubber	SD	=	Spray dry / Dry scrubber
SW	=	Seawater scrubber	INT	=	Removal integral to process

Particulate Removal Method:

ESP	=	Electrostatic precipitator	GCL	=	Hot gas cleanup

NOx Control Method:

LNB	=	Low NOx burners	OFA	=	Overfire air

Table A-2: Generation Efficiency and Lead Times

Table A-3: Generation Investment and Operation & Maintenance (O&M) Costs

Table A-4: Generation Technology Availabilities

Table A-5: Generation NO_x and SO_2 Emissions Rates

Table A-6: Generation CO_2 and Particulate Emissions Rates

Table A-7: Solid Waste and By-Product Generation

Table A-1: Generation Technology Basic Configurations

Technology	Nameplate Capacity	Cooling Water Method	Sulfur Controls Removal Tech.	Sulfur Controls Rem. Eff.	PM10 Controls Control Tech.	PM10 Controls Rem. Eff.	NOx Controls Control Tech.	NOx Controls Rem. Eff.
Unit:	(MW)			(%)		(%)		(%)
Oil/Gas								
Diesel_O3	3						LNB	50.0
Gas/Combustion Turbine Technologies								
Adv_CT_155	155	CL					LNB	70.0
Gas Turbine Combined-Cycle Technologies								
Adv_CC_250_OC	250	OC					LNB	70.0
Adv_CC_250_WC	250	WC					LNB	70.0
Adv_CC_500_OC	500	OC					LNB	70.0
Adv_CC_500_WC	500	WC					LNB	70.0
Adv_CC_750_OC	750	OC					LNB	70.0
Adv_CC_750_WC	750	WC					LNB	70.0
Conventional Coal Technologies (Subcritical)								
PCoal_300_OC	300	OC	-		ESP	99.0	LNB+OFA	50.0
PCoal_300_WC	300	WC	-		ESP	99.0	LNB+OFA	50.0
PCoal_300_OC_WS	300	OC	WS	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_300_OC_SW	300	OC	SW	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_300_WC_WS	300	WC	WS	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_300_WC_SW	300	WC	SW	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_600_OC	600	OC	-		ESP	95.0	LNB+OFA	50.0
PCoal_600_WC	600	WC	-		ESP	95.0	LNB+OFA	50.0
PCoal_600_OC_WS	600	OC	WS	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_600_OC_SW	600	OC	SW	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_600_WC_WS	600	WC	WS	90.0	ESP	95.0	LNB+OFA	50.0
PCoal_600_WC_SW	600	WC	SW	90.0	ESP	95.0	LNB+OFA	50.0
Clean Coal Technologies						99.0		
AFB_300_OC	300	OC	INT	95.0	ESP	99.0		
AFB_300_WC	300	WC	INT	95.0	ESP	99.0		
IGCC_500_OC	500	OC	INT	99.0	GCL	95.0		
IGCC_500_WC	500	WC	INT	99.0	GCL	95.0		
Nuclear								
MHTGR_113_OC	113	OC						
MHTGR_113_WC	113	WC						
ALWR_600_OC	600	OC						
ALWR_1000_OC	1000	OC						
Other								
Wind Onshore	0.75							
Wind Offshore	1.50							
Spark Ignition Engine	2.00							

Table A-2: Generation Efficiency and Lead Times

Technology	Average Efficiency LHV	Average Heat Rate LHV	Average Heat Rate LHV	CETP Lead Time Total Yrs.	Canc.	Const.
Unit:	(%)	(Btu/kWh)	(kJnet/kWh)	(Yr)	(Yr)	(Yr)
Oil/Gas	(Net Energy to Grid)					
Diesel_O3	30.0	11377	12002	1	0	1
Gas/Combustion Turbine Technologies						
Adv_CT_155	38.0	8982	9476	3	1	2
Gas Turbine Combined-Cycle Technologies						
Adv_CC_250_OC	58.0	5884	6208	4	2	2
Adv_CC_250_WC	57.5	5936	6262	4	2	2
Adv_CC_500_OC	58.0	5884	6208	5	2	3
Adv_CC_500_WC	57.5	5936	6262	5	2	3
Adv_CC_750_OC	58.0	5884	6208	6	2	4
Adv_CC_750_WC	57.5	5936	6262	6	2	4
Conventional Coal Technologies (Subcritical)						
PCoal_300_OC	36.0	9481	10002	5	2	3
PCoal_300_WC	35.5	9614	10143	5	2	3
PCoal_300_OC_WS	35.0	9751	10288	5	2	3
PCoal_300_OC_SW	35.0	9751	10288	5	2	3
PCoal_300_WC_WS	34.5	9893	10437	5	2	3
PCoal_300_WC_SW	34.5	9893	10437	5	2	3
PCoal_600_OC	37.0	9224	9732	6	2	4
PCoal_600_WC	36.5	9351	9865	6	2	4
PCoal_600_OC_WS	36.0	9481	10002	6	2	4
PCoal_600_OC_SW	36.0	9481	10002	6	2	4
PCoal_600_WC_WS	35.5	9614	10143	6	2	4
PCoal_600_WC_SW	35.5	9614	10143	6	2	4
Clean Coal Technologies						
AFB_300_OC	38.0	8982	9476	5	2	3
AFB_300_WC	37.5	9101	9602	5	2	3
IGCC_500_OC	45.0	7584	8002	6	2	4
IGCC_500_WC	44.5	7670	8091	6	2	4
Nuclear						
MHTGR_113_OC	45.0	7584	8002	4	2	2
MHTGR_113_WC	44.5	7670	8091	4	2	2
ALWR_600_OC	33.0	10342	10911	8	3	5
ALWR_1000_OC	33.0	10342	10911	8	3	5
Other						
Wind Onshore				2	1	1
Wind Offshore				3	2	1
Spark Ignition Engine	30.0	11373	12000	5	4	1

Table A-3: Generation Investment and Operation & Maintenance (O&M) Costs

Technology	Overnight Cost	Fixed O&M Costs	Variable O&M Costs	Overnight Cost	Fixed O&M Costs	Variable O&M Costs
Unit:	($99/kW)	($/kW-yr)	($/MWh)	(¥99/kW)	(¥/kW-yr)	(¥/MWh)
Oil/Gas					(¥8 = $1)	
Diesel_O3	300	2	5.0	2400	16	40
Gas/Combustion Turbine Technologies						
Adv_CT_155	400	1	3.0	3200	8	24
Gas Turbine Combined-Cycle Technologies						
Adv_CC_250_OC	600	12	0.5	4800	96	4
Adv_CC_250_WC	600	14	0.5	4800	112	4
Adv_CC_500_OC	600	11	0.5	4800	88	4
Adv_CC_500_WC	600	13	0.5	4800	104	4
Adv_CC_750_OC	600	10	0.5	4800	80	4
Adv_CC_750_WC	600	12	0.5	4800	96	4
Conventional Coal Technologies (Subcritical)						
PCoal_300_OC	600	20	1.0	4800	160	8
PCoal_300_WC	590	21	1.0	4720	168	8
PCoal_300_OC_WS	670	22	4.0	5360	176	32
PCoal_300_OC_SW	624	22	2.0	4992	176	16
PCoal_300_WC_WS	660	23	4.0	5280	184	32
PCoal_300_WC_SW	614	23	2.0	4912	184	16
PCoal_600_OC	550	18	1.0	4400	144	8
PCoal_600_WC	540	19	1.0	4320	152	8
PCoal_600_OC_WS	620	20	4.0	4960	160	32
PCoal_600_OC_SW	574	20	2.0	4592	160	16
PCoal_600_WC_WS	610	20	4.0	4880	160	32
PCoal_600_WC_SW	564	21	2.0	4512	168	16
Clean Coal Technologies						
AFB_300_OC	900	30	4.0	7200	240	32
AFB_300_WC	880	31	4.0	7040	248	32
IGCC_500_OC	1200	30	1.0	9600	240	8
IGCC_500_WC	1200	31	1.0	9600	248	8
Nuclear						
MHTGR_113_OC	1000	30	0.5	8000	240	4
MHTGR_113_WC	1000	31	0.5	8000	248	4
ALWR_600_OC	1500	40	0.5	12000	320	4
ALWR_1000_OC	1400	42	0.5	11200	336	4
Other						
Wind Onshore	650	15	5.0	5200	120	40
Wind Offshore	800	20	5.0	6400	160	40
Spark Ignition Engine	800	60	0.5	6400	480	4

Table A-4: Generation Technology Availabilities

Technology	Technology Availability In World Order	In World On-Line	In Shandong Order	In Shandong On-Line	Scheduled Maintenance	Equiv. Forced Outage Rate
Unit:	(Yr)	(Yr)	(Yr)	(Yr)	(wks/yr)	(%)
Oil/Gas						
Diesel_O3	1999	2000	1999	2000	0	5
Gas/Combustion Turbine Technologies						
Adv_CT_155	1997	2000	2005	2008	1	8
Gas Turbine Combined-Cycle Technologies						
Adv_CC_250_OC	1996	2000	2011	2015	3	5
Adv_CC_250_WC	1996	2000	2011	2015	3	5
Adv_CC_500_OC	1995	2000	2010	2015	3	5
Adv_CC_500_WC	1995	2000	2010	2015	3	5
Adv_CC_750_OC	1994	2000	2009	2015	3	5
Adv_CC_750_WC	1994	2000	2009	2015	3	5
Conventional Coal Technologies (Subcritical)						
PCoal_300_OC	1995	2000	1995	2000	7	5
PCoal_300_WC	1995	2000	1995	2000	7	5
PCoal_300_OC_WS	1995	2000	1995	2000	7	5
PCoal_300_OC_SW	1995	2000	1995	2000	7	5
PCoal_300_WC_WS	1995	2000	1995	2000	7	5
PCoal_300_WC_SW	1995	2000	1995	2000	7	5
PCoal_600_OC	1994	2000	1994	2000	8	5
PCoal_600_WC	1994	2000	1994	2000	8	5
PCoal_600_OC_WS	1994	2000	1994	2000	8	5
PCoal_600_OC_SW	1994	2000	1994	2000	8	5
PCoal_600_WC_WS	1994	2000	1994	2000	8	5
PCoal_600_WC_SW	1994	2000	1994	2000	8	5
Clean Coal Technologies						
AFB_300_OC	1995	2000	2005	2010	5	5
AFB_300_WC	1995	2000	2005	2010	5	5
IGCC_500_OC	1994	2000	2006	2012	5	8
IGCC_500_WC	1994	2000	2006	2012	5	8
Nuclear						
MHTGR_113_OC	2011	2015	2011	2015	2	5
MHTGR_113_WC	2011	2015	2011	2015	2	5
ALWR_600_OC	2002	2010	2002	2010	4	5
ALWR_1000_OC	2002	2010	2002	2010	4	5
Other						
Wind Onshore	1998	2000	1998	2000	0	5
Wind Offshore	2000	2003	2000	2003	0	5
Spark Ignition Engine	2000	2005	2000	2005	5	5

Table A-5: Generation NO_x and SO_2 Emissions Rates

Technology	NOx Emissions NOx Uncontrolled	Rem. Eff.	NOx Controlled		SO2 Emissions SOx Uncontrolled	Rem. Eff.	SOx Controlled
Unit:	(kg/GJnet)	(%)	(kg/GJnet)	•	(kg/GJnet)	(%)	(kg/GJnet)
Oil/Gas							
Diesel_O3	2.1104	50.0	1.0552		0.1387	0.0	0.1387
Gas/Combustion Turbine Tech							
Adv_CT_155	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Gas Turbine Combined-Cycle T							
Adv_CC_250_OC	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Adv_CC_250_WC	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Adv_CC_500_OC	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Adv_CC_500_WC	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Adv_CC_750_OC	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Adv_CC_750_WC	0.0010	70.0	0.0003		0.0003	0.0	0.0003
Conventional Coal Technologi							
PCoal_300_OC	0.4279	50.0	0.2140	•	0.7392	0.0	0.7392
PCoal_300_WC	0.4279	50.0	0.2140	•	0.7392	0.0	0.7392
PCoal_300_OC_WS	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_300_OC_SW	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_300_WC_WS	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_300_WC_SW	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_600_OC	0.4279	50.0	0.2140	•	0.7392	0.0	0.7392
PCoal_600_WC	0.4279	50.0	0.2140	•	0.7392	0.0	0.7392
PCoal_600_OC_WS	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_600_OC_SW	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_600_WC_WS	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
PCoal_600_WC_SW	0.4279	50.0	0.2140	•	0.7392	90.0	0.0739
Clean Coal Technologies							
AFB_300_OC	*0.4279*	73.8	0.1121	•	0.7392	95.0	0.0370
AFB_300_WC	*0.4279*	73.8	0.1121	•	0.7392	95.0	0.0370
IGCC_500_OC	*0.4279*	69.8	0.1292	•	0.7392	99.0	0.0074
IGCC_500_WC	*0.4279*	69.8	0.1292	•	0.7392	99.0	0.0074
Nuclear							
MHTGR_113_OC							
MHTGR_113_WC							
ALWR_600_OC							
ALWR_1000_OC							
Other							
Wind Onshore							
Wind Offshore							
Spark Ignition Engine	0.0597	0.0	0.0597		0.0192	0.0	0.0192

Underline & bullet means multiply uncontrolled by weight percent sulfer for emissions rate.

Table A-6: Generation CO_2 and Particulate Emissions Rates

Technology	CO2 Emissions CO2 Uncontrolled	Rem. Eff.	CO2 Controlled	Particulate (PM10) Emissions PM-10 Uncontrolled	Rem. Eff.	PM-10 Controlled
Unit:	• (kg/GJnet)	(%)	(kg/GJnet)	• (kg/GJnet)	(%)	(kg/GJnet)
Oil/Gas						
Diesel_O3	78.4804	0.0	78.4804	0.0274	0.0	0.0274
Gas/Combustion Turbine Technologies						
Adv_CT_155	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Gas Turbine Combined-Cycle Technologies						
Adv_CC_250_OC	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Adv_CC_250_WC	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Adv_CC_500_OC	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Adv_CC_500_WC	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Adv_CC_750_OC	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Adv_CC_750_WC	56.2948	0.0	56.2948	0.0032	0.0	0.0032
Conventional Coal Technologies (Subcritical)						
PCoal_300_OC	• 1.4123	0.0	1.4123	• 0.0516	99.0	0.0005
PCoal_300_WC	• 1.4123	0.0	1.4123	• 0.0516	99.0	0.0005
PCoal_300_OC_WS	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_300_OC_SW	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_300_WC_WS	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_300_WC_SW	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_600_OC	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_600_WC	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_600_OC_WS	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_600_OC_SW	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_600_WC_WS	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
PCoal_600_WC_SW	• 1.4123	0.0	1.4123	• 0.0516	95.0	0.0026
Clean Coal Technologies						
AFB_300_OC	• 1.4123	0.0	1.4123	• 0.2412	99.0	0.0024
AFB_300_WC	• 1.4123	0.0	1.4123	• 0.2412	99.0	0.0024
IGCC_500_OC	• 1.4123	0.0	1.4123	• 0.0063	95.0	0.0003
IGCC_500_WC	• 1.4123	0.0	1.4123	• 0.0063	95.0	0.0003
Nuclear						
MHTGR_113_OC						
MHTGR_113_WC						
ALWR_600_OC						
ALWR_1000_OC						
Other						
Wind Onshore						
Wind Offshore						
Spark Ignition Engine	21.3270	0.0	21.3270	0.0098	0.0	0.0098
	Underline & bullet means multiply uncontrolled by weight percent CO2 for emissions rate.			Underline & bullet means multiply uncontrolled by weight percent PM10 for emissions rate.		

Table A-7: Solid Waste and By-Product Generation

Technology	Total Water Consump.	FGD/FBD Limestone Consump.	Solid "Wastes" Tot. Solid By-Products (kg/MWh)	(kg/MWh)	Co-Products Gypsum Production	Sulfur Production
Unit:	(m3/MWh)	• (kg/MWh)	• (X % Ash)	• (X % S)	• (kg/MWh)	• (kg/MWh)
Oil/Gas						
Diesel_O3	0.0000					
Gas/Combustion Turbine Technologies						
Adv_CT_155	0.0011					
Gas Turbine Combined-Cycle Technologies						
Adv_CC_250_OC	0.0356					
Adv_CC_250_WC	0.4779					
Adv_CC_500_OC	0.0352					
Adv_CC_500_WC	0.4775					
Adv_CC_750_OC	0.0353					
Adv_CC_750_WC	0.4773					
Conventional Coal Technologies (Subcritical)						
PCoal_300_OC	0.0267		• 4.07	• 0.00		
PCoal_300_WC	0.7593		• 4.07	• 0.00		
PCoal_300_OC_WS	0.0998	• 13.149	• 4.07	• 0.00	• 22.500	
PCoal_300_OC_SW	0.0267		• 4.07	• 0.00		
PCoal_300_WC_WS	0.8324	• 13.149	• 4.07	• 0.00	• 22.500	
PCoal_300_WC_SW	0.7593		• 4.07	• 0.00		
PCoal_600_OC	0.0267		• 4.07	• 0.00		
PCoal_600_WC	0.7593		• 4.07	• 0.00		
PCoal_600_OC_WS	0.0998	• 13.149	• 4.07	• 0.00	• 22.500	
PCoal_600_OC_SW	0.0267		• 4.07	• 0.00		
PCoal_600_WC_WS	0.8324	• 13.149	• 4.07	• 0.00	• 22.500	
PCoal_600_WC_SW	0.7593		• 4.07	• 0.00		
Clean Coal Technologies						
AFB_300_OC	0.0260	• 21.286	• 3.92	• 25.00		
AFB_300_WC	0.6157	• 21.286	• 3.92	• 25.00		
IGCC_500_OC	0.0577	• 37.160	• 5.35	• 0.00		• 2.718
IGCC_500_WC	0.5447	• 37.160	• 5.35	• 0.00		• 2.718
Nuclear						
MHTGR_113_OC	0.0582					
MHTGR_113_WC	0.5447					
ALWR_600_OC	0.0267					
ALWR_1000_OC	0.7593					
Other						
Wind Onshore						
Wind Offshore						
Spark Ignition Engine						
		Multiply by wgt. % sulfur	Multiply by wgt. % ash	Multiply by wgt. % sulfur	Multiply by wgt. % sulfur	Multiply by wgt. % sulfur

Prepared by Stephen Connors

APPENDIX B: FLUE GAS DESULFURIZATION CHARACTERISTICS AND COSTS

	Unit	Spray Dry			Wet Method		
		PC/FGD (spray dry)	Spray Dry	Gas Suspension Absorption (GSA)	Advanced Flue Gas Desulfurization (absorber tower + reaction tank)	Gypsum-limestone (wet scrubber)	Sea Water Scrubber
Where		China	China	US	US	China	China
Manufacturer		(modeled)		AirPol, Inc.	Pure Air on the Lake, L. P.		
Source		DOE/CAS Study	Shandong Power	DOE CC	DOE CC Program	Shandong Power	Shandong Power
Design & Operation							
Unit Size	MW	200		10	100 300 500		
Generation Cap.	GWh/yr						
Annual Operation Hours	hrs/yr						
Capacity Factor	%						
Generation	GWh/yr						
Ca/S mole ratio							
Coal Sulfur Content	%		1 -3			> 1.0	< 2
Absorbent			Lime			Limestone	Sea Water
Scaling			Yes			Yes	No
Space Required			Large			Large	Large
Environmental							
SO_2 removal	%	88-94	70 -90	90-95	95-99.5	> 90	> 90
NOx removal	%	82					
Particulates removal	%	95-98					
Water consumption	%	0%					
Cost		(1997$)		(1990$)	(1995$)		
FGD / total Inv.	%		10-15			15-20	7-8
Capital Cost	$/kW	1652		149	210 121 94		
	K$						
Total O&M	$/kW	3155					
	K$/yr						
Material	K$/yr						
Mantanance	K$/yr						
Personnal	K$/yr						
Depreciation	K$/yr						
Cost in Yuan	¥8:$1 exchange rate						
Capital Cost	¥/kW	13546		1222	1722 992 771		
	K¥ Total						
Total O&M	¥/kW	25871					
	K¥/yr						
Material	K¥/yr						
Mantanance	K¥/yr						
Personnal	K¥/yr						
Depreciation	K¥/yr						
Other Costs							
DeS cost	¥/KgSO_2						
Generation Cost Incr.	¥/kWh						
SO_2 reduction	kg/yr						
SO_2 emission fee saved	¥/KgSO_2						
	K¥						

APPENDIX B: Flue Gas Desulfurization Characteristics and Costs (cont.)

	Unit	Furnance Sorbent Injection							
		LIFAC Sorbent Injection Desulfurization				IFAC with limestone pulverization		IFAC, purchase pulverized limestone	
Where		US			China	China		China	
Manufacturer		LIFAC-North America				designed coal	adjusted coal	designed coal	adjusted coal
Source		DOE CC Program			Shandong Power	Shandong Electric Power			
Design & Operation									
Unit Size	MW	300	150	65		12.00	12.00	12.00	12.00
Generation Cap.	GWh/yr					66.0	66.0	66.0	66.0
Annual Operation Hours	hrs/yr					5500	5500	5500	5500
Capacity Factor	%					62.8	62.8	62.8	62.8
Generation	GWh/yr								
Ca/S mole ratio						1.5	1.5	1.5	1.5
Coal Sulfur Content	%				< 2				
Absorbent		Limestone			Limestone	Limestone		Limestone	
Scaling					Yes				
Space Required					Small				
Environmental									
SO2 removal	%	70%			60 -85	60-70	60-70	60-70	60-70
NOx removal	%								
Particulates removal	%								
Water consumption	%								
Cost		(1990$)							
FGD / total Inv.	%				7				
Capital Cost	$/kW	66	76	99		12	12	4	4
	K$					142	142	49	49
Total O&M	$/kW								
	K$/yr								
Material	K$/yr								
Mantanance	K$/yr								
Personnal	K$/yr								
Depreciation	K$/yr								
Cost in Yuan	¥8:$1 exchange rate								
Capital Cost	¥/kW	541	623	812		97	97	34	34
	K¥ Total					1163	1163	405	405
Total O&M	¥/kW								
	K¥/yr								
Material	K¥/yr								
Mantanance	K¥/yr								
Personnal	K¥/yr								
Depreciation	K¥/yr								
Other Costs									
DeS cost	¥/KgSO2					0.492	0.338	0.916	0.855
Generation Cost Incr.	¥/kWh					0.014	0.017	0.027	0.042
SO2 reduction	kg/yr					2772550	3273270	2772550	3273270
SO2 emission fee saved	¥/KgSO2					0.2	0.2	0.2	0.2
	K¥					36	60.8	36	60.8

APPENDIX B: Flue Gas Desulfurization Characteristics and Costs (cont.)

	Unit	In-duct Lime Sorbent Injection	Semi-Dry FGD		
		Confined Zone Dispersion FGD	Demon-stration Plant	Adjusted cost	Commercial Estimate
Where		US	Shandong Huangdao		
Manufacturer		Bechtel Corporation			
Source		DOE CC Program	Shandong Power		
Design & Operation					
Unit Size	MW	500	83.3	83.3	200
Generation Cap.	GWh/yr		458.15	458.15	1100
Annual Operation Hours	hrs/yr		5500	5500	5500
Capacity Factor	%		62.8	62.8	62.8
Generation	GWh/yr				
Ca/S mole ratio					
Coal Sulfur Content	%				
Absorbent		Lime	Lime		
Scaling					
Space Required					
Environmental					
SO2 removal	%	50	70	70	70
NOx removal	%				
Particulates removal	%				
Water consumption	%				
Cost		(1990$)			
FGD /total Inv.	%				
Capital Cost	$/kW	<30	159	108	52
	K$		13247	9032	10366
Total O&M	$/kW				
	K$/yr		2256	1800	2856
Material	K$/yr		651	651	1563
Mantanance	K$/yr		331	226	259
Personnal	K$/yr		171	171	171
Depreciation	K$/yr		1103	825	863
Cost in Yuan	¥8:$1 exchange rate				
Capital Cost	¥/kW	308	1304	889	425
	K¥ Total		108625	74063	85000
Total O&M	¥/kW				
	K¥/yr		18503	14763	23420
Material	K¥/yr		5339	5339	12815
Mantanance	K¥/yr		2716	1852	2125
Personnal	K¥/yr		1400	1400	1400
Depreciation	K¥/yr		9048	6769	7080
Other Costs					
DeS cost	¥/KgSO2				
Generation Cost Incr.	¥/kWh		0.404	0.032	0.021
SO2 reduction	kg/yr		4125000	4125000	9900000
SO2 emission fee saved	¥/KgSO2				
	K¥				

Prepared by Chia-Chin Cheng

APPENDIX C: ESS MODELING ASSUMPTIONS FOR STEAM COAL

This appendix summarizes the coal cost and composition assumptions of the CETP's Electric Sector Simulation Task. Each type of coal modeled has a pre-specified quality, cost and cost trajectory for 2000 to 2024. The information on quality is important because it is related to coal's energy content and determines the base pollutant emissions; whereas the cost of coal is an important part of the production costs of generation units.

As described in CHAPTER 6: CLASSIFICATION OF STEAM COAL FOR ELECTRIC SECTOR SIMULATION SCENARIOS, each modeled coal is classified according to its source, mode(s) of transport, type, energy content and sulfur content. For purposes of modeling we ascribe fuel codes according to these characteristics as well as their production province of origin, transportation mode and preparation method (see Table C.2). Total carbon, ash and moisture content are approximated according to the general composition of coal produced in Shandong and Shanxi Provinces. The approximation of the coal quality is described in detail in the Classification chapter. This way of classifying delivered coal enables us to estimate coal costs in our model according not only to energy content but also to transportation distance and mode, and its level of preparation.

For comparison of ESS results with the work of other CETP analytical teams, we developed a parameter – tonne-km of coal transportation. The average transportation distances of steam coal by rail, rail/ship and truck within Shandong and to Shandong from other provinces are listed in Table C.1. However, the tonne-km transportation parameter is not used for calculation of the transportation costs in the initial ESS scenario sets for simplified assumption.

TABLE C.1: *Average Transportation Distances for Various Steam Coals*

	Average Coal Transport Distances						
Transpor-	*Shandong*			*Shanxi*			*Inn.Mong.*
Tation		Mine		Mine		Rail/	Rail/
Mode	Truck*	Mouth	Rail	Mouth	Rail	Ship	Ship
Local	20	1		1			
Rail			70		760	780	1342
Ship						450	411
Total	20	1	70	1	760	1230	1753
	(km)			*(km)*			*(km)*

*Note: Truck Transport classifications are not currently included in ESS's Modeling

To reflect future uncertainties in delivered cost of coal due to general and structural changes in the Chinese coal industry, as well as those related to the transportation of coal, alternative cost trajectories for coal costs have been chosen. These are described in detail in CHAPTER 7: COAL COST ASSUMPTIONS AND COAL COST UNCERTAINTY DEVELOPMENT. In the ESS study, the cost of coal is modeled with three uncertainties (trajectories) that relate to market structure and coal production technology: Business As Usual (I), Market Stabilization (O) and Production Innovation (U). The fourth uncertainty, Aggravated Transportation (A) case, deals with change in transportation cost. All trajectories take into account the effect of inflation. However, we assume the individual parameter costs (e.g. those attributable to transportation, subsidization and preparation) vary only with inflation in the (I), (O) and (U) cases. In the (A) case, we change the transportation cost trajectory to reflect the cost increase that might occur when the railroad capacity from outside Shandong province reaches its limit and investment to increase rail transport and reflected in transportation costs.

TABLE C.2: *ESS Coal Classification Code Table*

Digit 1 - Transportation Method

Coal Source	Mine Mouth	Rail	Rail / Ship
Shandong	M	D	–
Shanxi	P	X	S
Inner Mongolia (Batou)	–	–	B

Digit 2 – Coal Type

Coal Type and Treatment	Type Code
Anthracite	A
Meager – Raw	M
Meager – Prepared	R
Meager-Washed	G
Bituminous – Raw	B
Bituminous – Prepared	P
Bituminous – Washed	T
Lignite	L

Digit 3 (Sulfur Content) & Digit 4 (Energy Content)

Sufur Content (%S) — *empty*

Sulfur Content (%S)		(1) LHV < 22	(2) 22 ≤ LHV < 23	(3) 23 ≤ LHV < 24	(4) 24 ≤ LHV < 25	(5) 25 ≤ LHV
2.0 ≤ %S	(5)	51	52	53	54	55
1.5 ≤ %S < 2.0	(4)	41	42	43	44	45
1.0 ≤ %S < 1.5	(3)	31	32	33	34	35
0.5 ≤ %S < 1.0	(2)	21	22	23	24	25
0.0 < %S < 0.5	(1)	11	12	13	14	15

Sulfer & Energy Content at Midpoint

Energy Content (LHV – GJn / tonne)

Example: **DM32** = Shandong Meager Coal (raw / unprepared), Transported by Rail, 1.25 wgt. % S, 22.5 GJn / tonne energy

TABLE C.3: *ESS Coal Types and Baseline Assumptions*

ESS COAL Fuels							Fuel Emissions (Uncontrolled)		
Fuel Code	Source Province	Mode of Transport	Coal Type	Energy Content (GJn/t)	Base Year(1999) Energy Cost (¥/GJn)	(¥/GJn)	Total Sulfur (wgt.%S)	Total Carbon (wgt.%C)	Ash Content (wgt.%A)
DB31	Shandong	Rail	Bituminous	21.50	7.76	0.970	1.25	39.81	29.09
DB41	Shandong	Rail	Bituminous	21.50	7.76	0.970	1.75	39.81	29.09
DB51	Shandong	Rail	Bituminous	21.50	7.76	0.970	2.50	39.81	29.09
DB22	Shandong	Rail	Bituminous	22.50	7.74	0.968	0.75	43.22	22.39
DB32	Shandong	Rail	Bituminous	22.50	7.74	0.968	1.25	43.22	22.39
DB42	Shandong	Rail	Bituminous	22.50	7.74	0.968	1.75	43.22	22.39
DB52	Shandong	Rail	Bituminous	22.50	7.74	0.968	2.50	43.22	22.39
DB23	Shandong	Rail	Bituminous	23.50	7.73	0.967	0.75	46.64	15.70
DB33	Shandong	Rail	Bituminous	23.50	7.73	0.967	1.25	46.64	15.70
DB43	Shandong	Rail	Bituminous	23.50	7.73	0.967	1.75	46.64	15.70
DP33	Shandong	Rail	(DB31)	23.92	8.07	1.009	1.08	48.07	16.00
DP43	Shandong	Rail	(DB41)	23.92	8.07	1.009	1.51	48.07	16.00
DP53	Shandong	Rail	(DB51)	23.92	8.07	1.009	2.15	48.07	16.00
DP24	Shandong	Rail	(DB22, DB23)	24.66	7.83	0.979	0.65	50.61	10.47
DP34	Shandong	Rail	(DB32, DB33)	24.66	7.83	0.979	1.08	50.61	10.47
DP44	Shandong	Rail	(DB42, DB43)	24.66	7.83	0.979	1.51	50.61	10.47
DP54	Shandong	Rail	(DB52)	24.43	8.02	1.003	2.15	49.82	12.32
DM31	Shandong	Rail	Meager	21.50	7.69	0.961	1.25	39.81	28.44
DM41	Shandong	Rail	Meager	21.50	7.69	0.961	1.75	39.81	28.44
DM51	Shandong	Rail	Meager	21.50	7.69	0.961	2.50	39.81	28.44
DM22	Shandong	Rail	Meager	22.50	7.68	0.960	0.75	43.22	26.24
DM32	Shandong	Rail	Meager	22.50	7.68	0.960	1.25	43.22	26.24
DM42	Shandong	Rail	Meager	22.50	7.68	0.960	1.75	43.22	26.24
DM52	Shandong	Rail	Meager	22.50	7.68	0.960	2.50	43.22	26.24
DM23	Shandong	Rail	Meager	23.50	7.67	0.958	0.75	46.64	24.04
DM33	Shandong	Rail	Meager	23.50	7.67	0.958	1.25	46.64	24.04
DM43	Shandong	Rail	Meager	23.50	7.67	0.958	1.75	46.64	24.04
DM14	Shandong	Rail	Meager	24.50	7.66	0.957	0.50	50.05	21.84
DM24	Shandong	Rail	Meager	24.50	7.66	0.957	0.75	50.05	21.84
DR33	Shandong	Rail	(DM31)	23.86	8.00	1.000	1.08	47.85	15.64
DR43	Shandong	Rail	(DM41)	23.86	8.00	1.000	1.51	47.85	15.64
DR53	Shandong	Rail	(DM51)	23.86	8.00	1.000	2.15	47.85	15.64
DR24	Shandong	Rail	(DM22)	24.82	7.96	0.994	0.65	51.16	14.43
DR34	Shandong	Rail	(DM32)	24.82	7.96	0.994	1.08	51.16	14.43
DR44	Shandong	Rail	(DM42)	24.82	7.96	0.994	1.51	51.16	14.43
DR54	Shandong	Rail	(DM52)	24.82	7.96	0.994	2.15	51.16	14.43
DR25	Shandong	Rail	(DM23, DM24)	26.22	7.74	0.968	0.65	55.92	12.62
DR35	Shandong	Rail	(DM33)	25.76	7.92	0.990	1.08	54.36	13.22
DR45	Shandong	Rail	(DM43)	25.76	7.92	0.990	1.51	54.36	13.22
DR15	Shandong	Rail	(DM14)	26.67	7.88	0.985	0.43	57.47	12.01

TABLE C.3: *ESS Coal Types and Baseline Assumptions* (cont.)

ESS COAL Fuels (cont.)							Fuel Emissions (Uncontrolled)		
Fuel Code	Source Province	Mode of Transport	Coal Type	Energy Content (GJn/t)	Base Year(1999) Energy Cost (¥/GJn)	(¥/GJn)	Total Sulfur (wgt.%S)	Total Carbon (wgt.%C)	Ash Content (wgt.%A)
XB31	Shanxi	Rail	Bituminous	21.50	8.45	1.057	1.25	39.81	29.09
XB41	Shanxi	Rail	Bituminous	21.50	8.45	1.057	1.75	39.81	29.09
XB51	Shanxi	Rail	Bituminous	21.50	8.45	1.057	2.50	39.81	29.09
XB22	Shanxi	Rail	Bituminous	22.50	8.41	1.051	0.75	43.22	22.39
XB32	Shanxi	Rail	Bituminous	22.50	8.41	1.051	1.25	43.22	22.39
XB42	Shanxi	Rail	Bituminous	22.50	8.41	1.051	1.75	43.22	22.39
XB52	Shanxi	Rail	Bituminous	22.50	8.41	1.051	2.50	43.22	22.39
XB23	Shanxi	Rail	Bituminous	23.50	8.37	1.047	0.75	46.64	15.70
XB33	Shanxi	Rail	Bituminous	23.50	8.37	1.047	1.25	46.64	15.70
XB43	Shanxi	Rail	Bituminous	23.50	8.37	1.047	1.75	46.64	15.70
XP33	Shanxi	Rail	(XB31)	23.92	8.62	1.078	1.08	48.07	16.00
XP43	Shanxi	Rail	(XB41)	23.92	8.62	1.078	1.51	48.07	16.00
XP53	Shanxi	Rail	(XB51)	23.92	8.55	1.068	2.15	48.07	16.00
XP24	Shanxi	Rail	(XB22, XB23)	24.66	8.44	1.055	0.65	50.61	10.47
XP34	Shanxi	Rail	(XB32, XB33)	24.66	8.44	1.055	1.08	50.61	10.47
XP44	Shanxi	Rail	(XB42, XB43)	24.66	8.44	1.055	1.51	50.61	10.47
XP54	Shanxi	Rail	(XB52)	24.43	8.71	1.089	2.15	49.82	12.32
XM31	Shanxi	Rail	Meager	21.50	8.39	1.048	1.25	39.81	28.44
XM41	Shanxi	Rail	Meager	21.50	8.39	1.048	1.75	39.81	28.44
XM51	Shanxi	Rail	Meager	21.50	8.39	1.048	2.50	39.81	28.44
XM22	Shanxi	Rail	Meager	22.50	8.34	1.043	0.75	43.22	26.24
XM32	Shanxi	Rail	Meager	22.50	8.34	1.043	1.25	43.22	26.24
XM42	Shanxi	Rail	Meager	22.50	8.34	1.043	1.75	43.22	26.24
XM52	Shanxi	Rail	Meager	22.50	8.34	1.043	2.50	43.22	26.24
XM23	Shanxi	Rail	Meager	23.50	8.30	1.038	0.75	46.64	24.04
XM33	Shanxi	Rail	Meager	23.50	8.30	1.038	1.25	46.64	24.04
XM43	Shanxi	Rail	Meager	23.50	8.30	1.038	1.75	46.64	24.04
XM14	Shanxi	Rail	Meager	24.50	8.27	1.033	0.50	50.05	21.84
XM24	Shanxi	Rail	Meager	24.50	8.27	1.033	0.75	50.05	21.84
XR33	Shanxi	Rail	(XM31)	23.86	8.63	1.079	1.08	47.85	15.64
XR43	Shanxi	Rail	(XM41)	23.86	8.63	1.079	1.51	47.85	15.64
XR53	Shanxi	Rail	(XM51)	23.86	8.63	1.079	2.15	47.85	15.64
XR24	Shanxi	Rail	(XM22)	24.82	8.56	1.070	0.65	51.16	14.43
XR34	Shanxi	Rail	(XM32)	24.82	8.56	1.070	1.08	51.16	14.43
XR44	Shanxi	Rail	(XM42)	24.82	8.56	1.070	1.51	51.16	14.43
XR54	Shanxi	Rail	(XM52)	24.82	8.56	1.070	2.15	51.16	14.43
XR25	Shanxi	Rail	(XM23, XM24)	26.22	8.31	1.039	0.65	55.92	12.62
XR35	Shanxi	Rail	(XM33)	25.76	8.50	1.062	1.08	54.36	13.22
XR45	Shanxi	Rail	(XM43)	25.76	8.50	1.062	1.51	54.36	13.22
XR15	Shanxi	Rail	(XM14)	26.67	8.45	1.056	0.43	57.47	12.01

TABLE C.3: *ESS Coal Types and Baseline Assumptions* (cont.)

ESS COAL Fuels (cont.)							Fuel Emissions (Uncontrolled)		
Fuel Code	Source Province	Mode of Transport	Coal Type	Energy Content (GJn/t)	Base Year(1999) Energy Cost (¥/GJn)	(¥/GJn)	Total Sulfur (wgt.%S)	Total Carbon (wgt.%C)	Ash Content (wgt.%A)
SB31	Shanxi	Rail/Ship	Bituminous	21.50	8.92	1.115	1.25	39.81	29.09
SB41	Shanxi	Rail/Ship	Bituminous	21.50	8.92	1.115	1.75	39.81	29.09
SB51	Shanxi	Rail/Ship	Bituminous	21.50	8.92	1.115	2.50	39.81	29.09
SB22	Shanxi	Rail/Ship	Bituminous	22.50	8.86	1.107	0.75	43.22	22.39
SB32	Shanxi	Rail/Ship	Bituminous	22.50	8.86	1.107	1.25	43.22	22.39
SB42	Shanxi	Rail/Ship	Bituminous	22.50	8.86	1.107	1.75	43.22	22.39
SB52	Shanxi	Rail/Ship	Bituminous	22.50	8.86	1.107	2.50	43.22	22.39
SB23	Shanxi	Rail/Ship	Bituminous	23.50	8.80	1.100	0.75	46.64	15.70
SB33	Shanxi	Rail/Ship	Bituminous	23.50	8.80	1.100	1.25	46.64	15.70
SB43	Shanxi	Rail/Ship	Bituminous	23.50	8.80	1.100	1.75	46.64	15.70
SP33	Shanxi	Rail/Ship	(SB31)	23.92	8.70	1.087	1.08	48.07	16.00
SP43	Shanxi	Rail/Ship	(SB41)	23.92	8.62	1.078	1.51	48.07	16.00
SP53	Shanxi	Rail/Ship	(SB51)	23.92	8.55	1.068	2.15	48.07	16.00
SP24	Shanxi	Rail/Ship	(SB22, SB23)	24.66	8.85	1.106	0.65	50.61	10.47
SP34	Shanxi	Rail/Ship	(SB32, SB33)	24.66	8.85	1.106	1.08	50.61	10.47
SP44	Shanxi	Rail/Ship	(SB42, SB43)	24.66	8.85	1.106	1.51	50.61	10.47
SP54	Shanxi	Rail/Ship	(SB52)	24.43	9.04	1.131	2.15	49.82	12.32
SM21	Shanxi	Rail/Ship	Meager	21.50	8.85	1.106	0.75	39.81	28.44
SM31	Shanxi	Rail/Ship	Meager	21.50	8.85	1.106	1.25	39.81	28.44
SM41	Shanxi	Rail/Ship	Meager	21.50	8.85	1.106	1.75	39.81	28.44
SM51	Shanxi	Rail/Ship	Meager	21.50	8.85	1.106	2.50	39.81	28.44
SM22	Shanxi	Rail/Ship	Meager	22.50	8.79	1.098	0.75	43.22	26.24
SM32	Shanxi	Rail/Ship	Meager	22.50	8.79	1.098	1.25	43.22	26.24
SM42	Shanxi	Rail/Ship	Meager	22.50	8.79	1.098	1.75	43.22	26.24
SM52	Shanxi	Rail/Ship	Meager	22.50	8.79	1.098	2.50	43.22	26.24
SM23	Shanxi	Rail/Ship	Meager	23.50	8.73	1.091	0.75	46.64	24.04
SM33	Shanxi	Rail/Ship	Meager	23.50	8.73	1.091	1.25	46.64	24.04
SM43	Shanxi	Rail/Ship	Meager	23.50	8.73	1.091	1.75	46.64	24.04
SM14	Shanxi	Rail/Ship	Meager	24.50	8.68	1.084	0.50	50.05	21.84
SM24	Shanxi	Rail/Ship	Meager	24.50	8.68	1.084	0.75	50.05	21.84
SR23	Shanxi	Rail/Ship	(SM21)	23.86	9.05	1.131	0.65	47.85	15.64
SR33	Shanxi	Rail/Ship	(SM31)	23.86	9.05	1.131	1.08	47.85	15.64
SR43	Shanxi	Rail/Ship	(SM41)	23.86	9.05	1.131	1.51	47.85	15.64
SR53	Shanxi	Rail/Ship	(SM51)	23.86	9.05	1.131	2.15	47.85	15.64
SR24	Shanxi	Rail/Ship	(SM22)	24.82	8.96	1.120	0.65	51.16	14.43
SR34	Shanxi	Rail/Ship	(SM32)	24.82	8.96	1.120	1.08	51.16	14.43
SR44	Shanxi	Rail/Ship	(SM42)	24.82	8.96	1.120	1.51	51.16	14.43
SR54	Shanxi	Rail/Ship	(SM52)	24.82	8.96	1.120	2.15	51.16	14.43
SR25	Shanxi	Rail/Ship	(SM23, SM24)	25.76	8.89	1.111	0.65	54.36	13.22
SR35	Shanxi	Rail/Ship	(SM33)	25.76	8.89	1.111	1.08	54.36	13.22
SR45	Shanxi	Rail/Ship	(SM43)	25.76	8.89	1.111	1.51	54.36	13.22
SR15	Shanxi	Rail/Ship	(SM14)	26.67	8.82	1.103	0.43	57.47	12.01

TABLE C.3: *ESS Coal Types and Baseline Assumptions* (cont.)

ESS COAL Fuels (cont.)							Fuel Emissions (Uncontrolled)		
Fuel Code	Source Province	Mode of Transport	Coal Type	Energy Content (GJn/t)	Base Year(1999) Energy Cost (¥/GJn)	(¥/GJn)	Total Sulfur (wgt.%S)	Total Carbon (wgt.%C)	Ash Content (wgt.%A)
DA22	Shandong	Rail	Anthracite	22.50	6.89	0.861	0.75	63.00	26.00
DA23	Shandong	Rail	Anthracite	23.50	6.87	0.859	0.75	66.00	24.00
DA33	Shandong	Rail	Anthracite	23.50	6.87	0.859	1.25	66.00	24.00
XA23	Shanxi	Rail	Anthracite	23.50	7.51	0.939	0.75	66.00	24.00
ML11	Shandong	Rail	Lignite	17.50	9.15	1.144	0.75	26.15	15.00
ML31	Shandong	Rail	Lignite	17.50	9.15	1.144	1.25	26.15	15.00
BB22	Mongolia	Rail/Ship	Bituminous	22.50	8.86	1.107	0.75	43.22	22.39
BB23	Mongolia	Rail/Ship	Bituminous	23.50	8.80	1.100	0.75	46.64	15.70
BB33	Mongolia	Rail/Ship	Bituminous	23.50	8.80	1.100	1.25	46.64	15.70
PL21	Shanxi	:oal by Wir	Lignite	17.50	9.15	1.144	0.75	26.15	15.00
PL31	Shanxi	:oal by Wir	Lignite	17.50	9.15	1.144	1.25	26.15	15.00

TABLE C.4: *Non-Coal Fuel Baseline Assumptions*

ESS Non-COAL Fuels					Fuel Emissions (Uncontrolled)		
Fuel Code	Fuel Type	Energy Content (GJn/t)	Base Year(1999) Energy Cost (¥/GJn)	(¥/GJn)	Total Sulfur (wgt.%S)	Total Carbon (wgt.%C)	Ash Content (wgt.%A)
NGAS	Pipeline Natural Gas	48.84	26.00	3.250	0.00	73.00	0.00
LNG	Liquified Natural Gas	48.84	32.00	4.000	0.00	75.00	0.00
DIES	Diesel Fuel (Oil2)	44.51	60.00	7.500	0.50	87.00	0.00
O616	Residual Oil (Oil6)	39.37	36.00	4.500	1.60	85.00	0.20
NUC3	Nuclear Fuel 3.25%	2850000	4.80	0.600	0.00	0.00	0.00
NUC8	Nuclear Fuel 8%	3880000	5.60	0.700	0.00	0.00	0.00
CBM	Coal Bed Methane				0.00	0.00	0.00
BioG	Bio-Gas				0.00	0.00	0.00

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