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Electricity Market Module
Electricity Capacity Planning Submodule
Updates for *AEO 1996*

June 1996

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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The purpose of this report is to describe modifications to the Electricity Capacity Planning Submodule (ECP) for the *Annual Energy Outlook 1996*. It describes revisions to enhance the representation of planned maintenance, incorporate technological improvements in operating efficiencies, revise the algorithm for determining international firm power imports, and include risk premiums for new plant construction.

Planned Maintenance

An endogenous representation of planned maintenance was initially implemented in the ECP for the *Annual Energy Outlook 1995* (AEO95).¹ This approach, which relied on an aggregate formulation, simulated maintenance scheduling by totaling the planned outages for all capacity types. The demands for electric power in the ECP were then adjusted to include the equivalent amount of electricity that could be produced by plants that were out-of-service due to maintenance. Therefore, the generating capacity available for satisfying customer loads was implicitly reduced because some capacity had to be allocated to meet the maintenance requirement.

The representation of planned maintenance in the ECP has been expanded for the *Annual Energy Outlook 1996* (AEO96). The revised formulation considers maintenance needs for individual capacity types.² Rather than increasing the load requirement, the capacity available for meeting customer loads is explicitly reduced to account for plants that are out-of-service. Compared to the original formulation, the new structure increases the model size and execution time but improves the accuracy of dispatching decisions in the ECP. The new planned maintenance structure is described below.

Objective Function

The formulation of the objective function of the ECP is not changed by the new representation of planned maintenance. The planned maintenance decision variables do not have cost coefficients. However, the value of the objective function is indirectly affected since other technologies must be operated when a particular plant type is unavailable due to maintenance requirements.

Planned Maintenance Constraints

The revised *Planned Maintenance* constraints ensure that the total of the seasonal planned

¹For more information, see Energy Information Administration, *Model Documentation, Electricity Market Module, Modifications to the Electricity Capacity Planning Submodule*, DOE/EIA-M068-B/1 (Washington, DC, April 1995).

²Planned maintenance is represented for fossil and nuclear plants. Utilization rates for renewable technologies are provided by the Renewable Fuels Module and already account for planned maintenance.

maintenance scheduled for each dispatchable technology satisfies the annual maintenance requirements for that technology. These constraints are defined as

$$(1) \quad \sum_s \text{SHOURS}_s \cdot \text{PMC}_{yrcs} - \text{CPMR}_{rc} \cdot \text{EXC}_{yrc} - \sum_o \sum_{j=1}^y \text{CPMR}_{rc} \cdot \text{BLD}_{jrc} \geq 0$$

for every dispatchable capacity type c in year y and region r.

where:

- SHOURS_s = Hours in Season s (Thousands of Hours)
- PMC_{yrcs} = Planned Maintenance Scheduled for Dispatchable Capacity Type c in Year y in Season s in Region r (Gigawatts)
- CPMR_{rc} = Amount of Time Required for Planned Maintenance for Capacity Type c in Region r (Thousands of Hours)
- EXC_{yrc} = Utilize Existing Capacity Type c in Year y in Region r (Gigawatts)
- BLD_{jrc} = Build New Dispatchable Capacity Type c by Owner Type o Beginning Operation in Year j in Region r (Gigawatts)

The first term, $\text{SHOURS}_s \cdot \text{PMC}_{yrcs}$, contains the decision variable for planned maintenance and represents the total amount of maintenance allocated to each dispatchable capacity type over all seasons in each region and year. The terms, $\text{CPMR}_{rc} \cdot \text{EXC}_{yrc}$ and $\text{CPMR}_{rc} \cdot \text{BLD}_{jrc}$, define the annual maintenance requirements for each capacity type for existing and new capacity in each region. Therefore, the *Planned Maintenance* rows require that the total allocation of capacity type c for planned maintenance over all seasons equals or exceeds the annual requirements for that capacity type.

Dispatchable Capacity Balance Constraints

The *Capacity Balance* constraints for dispatchable capacity types, which limit production of electricity by the available generating capability, have been modified to include the allocation of capacity for maintenance requirements. *Capacity Balance* rows are now created for each season in order to incorporate the seasonal planned maintenance decision variable. The revised *Capacity Balance* constraints are given by

$$(2) \quad \sum_f \sum_m \text{OPD}_{yrcfms} - \sum_o \sum_{j=1}^y \text{BLD}_{jrc} + \sum_{j=1}^y \text{FGD}_{jrc} - \sum_{j=1}^y \text{FGD}_{jrc} + \sum_g \text{TRN}_{yrcg} - \sum_e \text{TRN}_{yrcr} \cdot \text{TLOSS}_{yrc} - \sum_o \sum_{j=1}^y \text{BDI}_{jrc} \cdot \text{TLOSS}_{yrc} + \text{PMC}_{yrcs} - \text{EXC}_{yrc} \leq 0.0$$

for every dispatchable capacity type c and season s in year y in region r.

where:

- OPD_{yrcfms} = Allocate Dispatchable Capacity Type c Consuming Fuel f in Mode m in Season s in Year y in Region r (Gigawatts)
 BLD_{jrco} = Build New Dispatchable Capacity Type c by Owner Type o Beginning Operation in Year j in Region r (Gigawatts)
 FGD_{jrck} = Convert Existing Coal Capacity Type c (without scrubber) to Coal Capacity Type k (with scrubber) With the Retrofit Completed in Year j in Region r (Gigawatts).
 FGD_{jrkc} = Convert Existing Coal Capacity Type k (without scrubber) to Coal Capacity Type c (with scrubber) With the Retrofit Completed in Year j in Region r (Gigawatts).
 TRN_{yrcg} = Dispatchable Capacity Type c Transferred to Import Region g from Export Region r in Year y (Gigawatts)
 TRN_{yrecr} = Dispatchable Capacity Type c Transferred from Export Region e to Import Region r in Year y (Gigawatts)
 $TLOSS_{yer}$ = 1 - Interregional Transmission Loss Factor from region e to region r in Year y (Fraction)
 BDI_{jecro} = Build Dispatchable Capacity Type c by Owner Type o in Export Region e for Import Region r in Year j (Gigawatts)
 PMC_{yscr} = Planned Maintenance Scheduled for Dispatchable Capacity Type c in Year y in Season s in Region r (Gigawatts)
 EXC_{yrc} = Utilize Existing Capacity Type c in Year y in Region r (Gigawatts)

In the *Capacity Balance* constraints for technology type c, terms with negative coefficients define the available capacity for region r in year y. These include new plants that have begun operation (BLD_{jrco}) and existing capacity (EXC_{yrc}). Other sources of supply are capacity purchases from another region e (TRN_{yrecr}) and new capacity built in another region e but owned by and serving load for region r (BDI_{jecro}), both of which must be adjusted for transmission losses. For capacity types c corresponding to scrubbed coal-fired plants, the available capacity can be increased by retrofitting existing units with scrubbers (FGD_{jrkc}).

Positive terms represent the disposition of the available capacity. These decision variables include the seasonal production of electricity (OPD_{yrcfms}), power exports to other regions g (TRN_{yrcg}), and seasonal maintenance scheduling (PMC_{yscr}). For the capacity types corresponding to unscrubbed coal-fired plants, capacity can also be retrofitted with scrubbers (FGD_{yrck}).

The revised *Capacity Balance* constraints differ from the previous formulation in two respects. The operate vectors (OPD_{yrcfms}) now have a seasonal representation. That is, they describe the mode of operation m (e.g., base, intermediate, peak) by season instead of by year. Also, the capacity available to meet demand is now explicitly reduced by the capacity that is out-of-service due to scheduled maintenance.

Electricity Load Requirement Constraints

The *Electricity Load Requirement* constraints specify that sufficient capacity must be allocated to meet the capacity and energy requirements for each load segment. They no longer contain

decision variables for maintenance scheduling, which are now accounted for by capacity type in the *Capacity Balance* rows. The revised constraints are defined as

$$\begin{aligned} & \sum_c \sum_f \sum_m ELA_{yrcfml} \cdot OPD_{yrcfm} + \sum_n ELR_{yrnl} \cdot OPR_{yrn} + \sum_i \sum_o \sum_{z=1}^y ELI_{zril} \cdot INT_{zrio} \\ & + ELH_{yrl} \cdot OPH_{yrl} + \sum_i ELI_{yri} \cdot EXI_{yri} + \sum_d \sum_{z=1}^y ELD_{yzrdl} \cdot DSM_{yrd} \\ & + \sum_i \sum_o \sum_e \sum_{z=1}^y ELI_{zril} \cdot TLOSS_{zer} \cdot BII_{zeiro} + \sum_s ELCH_{yrs1} \cdot BCH_{yrs} \geq ELC_{yrl} \end{aligned}$$

(3)

for every load step l in year y and region r .

where:

- ELA_{yrcfml} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, and Load Following Rates) for Dispatchable Capacity Allocated to Meet Capacity Requirements In Load Step l In Year y , Region r By Capacity Type c With Fuel f In Mode m (Fraction)
- OPD_{yrcfms} = Allocate Dispatchable Capacity Type c Consuming Fuel f in Mode m in Season s in Year y in Region r (Gigawatts)
- ELR_{yrnl} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, Load Following Rates and Availability of Resource) for Renewable Capacity Type n (Excluding Hydro) Allocated to Meet Capacity Requirements In Load Step l In Year y , Region r , By Capacity Type n (Fraction)
- OPR_{yrn} = Allocate Renewable Capacity Type n (Excluding Hydro) in Year y in Region r (Gigawatts)
- ELI_{zril} = Derating Factor (Availability of Resource) for Intermittents in Load Step l In Region r By Intermittent Technology Type i Beginning Operation in Year z (Fraction)
- INT_{zrio} = Utilize/Build Intermittent Renewable Type i for Owner Type o Beginning Operation in Year z in Region r (Gigawatts)
- ELH_{yrl} = Derating Factor (Availability of Resource) for Hydro in Load Step l In Region r By Beginning Operation in Year y (Fraction)
- OPH_{yrl} = Allocate Hydro Capacity in Vertical Load Step l in Year y in Region r (Gigawatts)
- EXI_{yri} = Available Existing Intermittent Capacity Type i in Year y in Region r (Gigawatts)
- ELD_{yzrdl} = Amount of Capacity Requirement Eliminated or Created In Load Step l In Year z By Demand Side Technology d Initiated In Year y , Region r

- (Fraction)
- DSM_{yrd} = Implement Demand-Side Management Technology d Starting in Year y in Region r (Gigawatt Equivalent)
- $TLOSS_{zer}$ = 1 - Interregional Transmission Loss Factor from region e to region r in Year z (Fraction)
- BII_{zeiro} = Build Intermittent Capacity Type i by Owner Type o in region e for region r in Year z (Gigawatts)
- $ELCH_{yrsl}$ = Derating Factor (Availability of Resource) for Imported Canadian Hydro Steps in Load Step l In Region r In Year y (Fraction)
- BCH_{yrs} = Build Canadian Hydro Capacity in Canadian Import Supply Step s for Region r in Year y (Gigawatts)
- ELC_{yrl} = Capacity Requirement In the Vertical Load Step l In Year y and Region r (Gigawatts)

The first term of the left-hand side of the equation represents electricity production from dispatchable plants. It incorporates the revised operate vector OPD_{yrcfms} , which describes the seasonal allocation of capacity. The next four terms are the supply contributions from intermittent technologies and other renewable capacity types. The sixth term describes the impact of demand-side management programs. The coefficients for demand-side management options can be either positive or negative since load shifting programs reduce load in some segments by creating load in other segments. The final two components of the equation represent renewable generating capacity built in another region that serves region r and Canadian power imports, respectively. Except for the revised operate vectors and the absence the planned maintenance decision variables, the modified *Electricity Load* rows are identical to the previous formulation.

Technological Improvements in Heatrates

For the AEO95, the ECP was modified to include reductions in capital costs due to learning effects. For the AEO96, a similar enhancement was implemented to include improvements in heatrates, which describe the amount of fuel input required to produce a kilowatthour of electricity. Table 1 contains the initial and final heatrates by technology type.

Table 1. Initial and Final Heatrates (Btu per kilowatthour)

Technology	Heatrate	
	Initial	Final
Pulverized Coal	9961	8142
Advanced Coal	8730	7582
Combined Cycle	7900	6824
Advanced Combined Cycle	7300	5687

Combustion Turbines	11900	10663
Advanced Combustion Turbines	9000	7935
Fuel Cells	6450	5687

For each of these technologies, it is assumed that the annual reduction in the heatrate is constant and occurs over a prespecified time period. The heat rate for technology type c in a particular year is given by

$$(4) \text{EPPHRT}_{yc} = \text{EPPHRT}_{0c} + (\text{EPPHRTN}_c - \text{EPPHRT}_{0c}) * \frac{(y - \text{UPDHR}_{Y0c})}{(\text{UPDHR}_{YNc} - \text{UPDHR}_{Y0c})}$$

for $\text{UPDHR}_{Y0c} \leq y \leq \text{UPDHR}_{YNc}$

$$\text{EPPHRT}_{yc} = \text{EPPHRT}_{0c} \quad \text{for } y < 1995$$

$$\text{EPPHRT}_{yc} = \text{EPPHRTN}_c \quad \text{for } y > 2010.$$

where: EPPHRT_{yc} = heatrate for technology type c in year y
 EPPHRT_{0c} = initial heatrate for technology type c
 EPPHRTN_c = final heatrate for technology type c
 UPDHR_{Y0c} = last year for initial heatrate for technology type c (i.e., year before heatrate improvements begin)
 UPDHR_{YNc} = last year of learning for heatrate for technology type c

International Firm Power Imports

The previous representation of international imports in the ECP Submodule allowed domestic utilities to invest in early development of foreign generation projects on a year-by-year basis with no lead time requirement. Unfortunately, these projects were frequently selected by the ECP because they were the only alternative to meet a short term surge in expected demands. Further, the following planning year the investment could be pulled back. This result was inconsistent with the cost assumptions used and is unrealistic. The ability of the ECP to alternatively commit and not commit to the Canadian imports contributed to an unstable solution to both the foreign and domestic generation capacity development.

The revised representation requires the domestic utilities to commit to the purchase of all output from a project between an accelerated project start date and the project start date announced by the foreign utility. Further all project start dates must conform to a reasonable lead time requirement. For example, if a Canadian hydro project is scheduled to start generation in 2010 to serve Canadian needs, then domestic utilities can accelerate the project start date by committing to purchase all the output of the project from the current year plus a lead time until 2010. In 2010 this capacity is assumed to be fully committed to the Canadian needs and is no longer available to the U.S. utilities except through economy trades determined by the Electricity

Fuel Dispatch (EFD). Appendix A contains a list of the potential Canadian projects.

Mathematical Representation

The new structure introduces three new classes of decision vectors and one new set of constraints:

Build Capacity Vector - $B(f)IMU(pc)(y)$ - Commit to project (pc) in foreign region (f) in planning period (y).

Existing Capacity Vector - $E(f)IMU(pc)(y)$ - Capacity available from project (pc) in foreign region (f) in planning period (y).

Operate Vector - $O(r)IM(f)X1(y)$ - Use derated capacity from foreign region (f) in domestic region (r) in planning period (y).

Capacity Balance Row - $C(f)IMDDD(y)$ - ensure that the capacity used from foreign region (f) in planning year (y) is no more than what is currently available.

The objective function of the build capacity vector is the total present value of building and operating the project from the current planning year plus a lead time to the original start date of the project or to the end of the planning horizon, whichever comes first. If selected this vector then feeds the capacity balance row for each planning year from the new start date to the original start date. Once the build vector has been selected in one planning cycle, the build vector is turned off and the existing capacity vector is activated and makes the capacity available in the capacity balance row for all the appropriate years. Note, both the build and existing vectors convert from full project capacity to derated capacity in the capacity balance row.

The operate vectors then use the capacity available in the capacity balance rows to meet demand by the U.S. utilities connected to the foreign utility. More than one U.S. utility region can connect to a foreign region and the utilization shares between the multiple regions can change from one planning year to the next and from one planning cycle to the next.

Risk Premiums

The ECP has been modified to incorporate risk premiums for the AEO96. The risk premiums adjust the discount rate used to determine the present value of costs in the objective function of the ECP.³ The risk premium is subtracted from the discount rate; therefore, the present value of costs using the "adjusted discount rate" will be higher than the same costs using the original

³The objective function of the ECP minimizes the total, discounted present value of the costs (i.e., revenue requirements) associated with the construction and operation of powerplants over the planning horizon. For more information on the objective function of the ECP, see Energy Information Administration, *Model Documentation: Electricity Market Module, Electricity Capacity Planning Submodule*, DOE/EIA-M068-B (Washington, DC, March, 1994).

discount rate.

Prior to the AEO96, the same discount rate was used to compute the present value of costs for all technologies. This discount rate was assumed to be the weighted, after-tax cost of capital. The risk premium used to adjust the discount rate for each technology is based on the assumed construction lead times.⁴ Table 2 contains the risk premiums by technology type.⁵

Table 2. Risk Premiums by Technology Type

Technology Type	Construction Leadtime (Years)	Risk Premium (Percent)
Pulverized Coal	4	1.325
Advanced Coal	4	1.325
Combined Cycle	3	0.750
Advanced Combined Cycle	3	0.750
Combustion Turbines	2	0.500
Advanced Combustion Turbines	2	0.500
Fuel Cells	2	0.500
Geothermal	3	0.750
Biomass	3	0.750
Wind	2	0.500
Solar Thermal	2	0.500
Solar Photovoltaic	2	0.500

⁴The licensing period, which is assumed to be one year, requires little capital investment and is not included. For a detailed description of the methodology and assumptions used to develop risk premiums, see the Attachment.

⁵ Risk premiums were developed for three different leadtimes—three years, five years, and seven years. The premiums for other leadtimes were determined using linear interpolation.

Canadian Supply Curve Assumptions

British Columbia

Project Name	Seller region	Summer Cap (megawatts)	Lead Time (years)	Start Year	Capacity Factor	cost/MW 1986\$	cost/MWH 1990\$	Forced Outage Rate
Moran	British Columbia	2270	5	2016	0.61	1201	27.96	0.05
Stave Ruskin	British Columbia	43	5	2016	0.40	1489	52.87	0.05
Kemano II	British Columbia	740	5	2016	0.62	1811	41.49	0.05
Bridge River Rapids	British Columbia	402	5	2016	0.67	1841	39.03	0.05
Elaho	British Columbia	195	5	2016	0.39	2129	77.53	0.05
Cottonwood Canyon	British Columbia	411	5	2016	0.51	2170	60.43	0.05
Yukon-Taku	British Columbia	2490	5	2016	0.67	2370	50.24	0.05
Cutoff Mountain	British Columbia	727	5	2016	0.67	2400	50.87	0.05
Stikine-Iskut	British Columbia	1733	5	2016	0.63	2531	57.06	0.05
Liard	British Columbia	2978	5	2016	0.62	2578	59.06	0.05
Peace River Site E	British Columbia	438	5	2016	0.80	2778	49.32	0.05
Homathko Development	British Columbia	548	5	2016	0.61	3166	73.71	0.05
Peace River Site C	British Columbia	526	5	2016	0.58	3201	78.38	0.05
Lower McGregor	British Columbia	187	5	2016	0.29	3320	162.59	0.05
Cheakamus-Brandywine	British Columbia	50	5	2016	0.26	3369	184.03	0.05
John Hart II	British Columbia	22	5	2016	0.18	3497	275.92	0.05
Keenleyside-Murphy*	British Columbia	156	5	2016	0.54	3509	92.29	0.05
Cariboo Falls	British Columbia	49	5	2016	0.39	3675	133.83	0.05
Gold River	British Columbia	84	5	2016	0.24	4854	287.25	0.05
Ucona Development	British Columbia	42	5	2016	0.15	5285	500.40	0.05
Kokish River	British Columbia	29	5	2016	0.18	5491	433.26	0.05
WANETA	British Columbia	380	4	2003	0.35	2330	94.56	0.05
KEENELEYSIDE	British Columbia	73	4	2006	0.54	2330	61.29	0.05
BRILLIANT	British Columbia	146	4	2007	0.35	2330	94.56	0.05
REVELSTOKE	British Columbia	900	4	2006	0.56	2330	59.10	0.05
SEVEN MILE	British Columbia	600	4	2000	0.44	2330	75.22	0.05
MICA	British Columbia	800	4	2005	0.54	2330	61.29	0.05

Manitoba

Project Name	Seller region	Summer Cap	Lead Time	Start Year	Capacity Factor	cost/MW 1986\$	cost/MWH 1990\$	Forced Outage Rate
LIMESTONE	Manitoba	777		1992	0.61	1774	41.30	0.05
Conawapa	Manitoba	768	5	2016	0.59	1984	47.76	0.05
Wuskwatim*	Manitoba	175	4	2011	0.74	1994	38.27	0.05
Birthday	Manitoba	365	5	2016	0.69	2255	46.42	0.05
Gull	Manitoba	308	5	2016	0.58	2410	59.01	0.05
First Rapids	Manitoba	160	5	2016	0.80	2521	44.76	0.05
Manasan	Manitoba	183	5	2016	0.73	2580	50.20	0.05
Gilliam Island	Manitoba	502	5	2016	0.62	2751	63.02	0.05
Whitemud & Red Rock	Manitoba	320	5	2016	0.63	2833	63.87	0.05
Notigi	Manitoba	80	5	2016	0.57	2955	73.63	0.05
Granville	Manitoba	91	5	2016	0.61	3748	87.26	0.05
Kelsey Extension	Manitoba	80	5	2016	0.33	3881	167.03	0.05

Quebec

Project Name	Seller region	Summer Cap	Lead Time	Start Year	Capacity Factor	cost/MW		cost/MWH	Rate	Forced Outage
						1986S	1990S			
BRISAY	Quebec	262	5	1993	0.68	2761	57.67		0.05	
Gull Island	Quebec	1292	5	2016	0.76	2799	52.31		0.05	
LaRomaine	Quebec	1011	5	2016	0.59	3028	72.89		0.05	
Chamouchouane	Quebec	628	5	2016	0.53	3094	82.91		0.05	
Notiway Broadback Rupter	Quebec	5308	5	2016	0.61	3294	76.69		0.05	
EASTMAIN 1*	Quebec	331	4	2006	0.65	3344	73.07		0.05	
EASTMAIN 2*	Quebec	134	4	2006	0.72	4576	90.27		0.05	
LAForge 1*	Quebec	544	4	1994	0.61	2845	66.24		0.05	
LAForge 2*	Quebec	289	4	1996	0.72	3344	65.96		0.05	
LAForge 3*	Quebec	274	4	2005	0.72	3344	65.96		0.05	
Muskral Falls	Quebec	533	5	2016	0.86	3443	56.86		0.05	
Caniapiscau	Quebec	1792	5	2016	0.80	3844	68.24		0.05	
George	Quebec	2215	5	2016	0.78	3943	71.80		0.05	
Maggie	Quebec	274	5	2016	0.77	4009	73.95		0.05	
Petit Mecatina	Quebec	1005	5	2016	0.76	4293	80.23		0.05	
Moisie	Quebec	811	5	2016	0.80	4326	76.80		0.05	
Saint-Louis et Archipel	Quebec	651	5	2016	0.80	4460	79.18		0.05	
La Baleine	Quebec	628	5	2016	0.78	4676	85.14		0.05	
Aguanus	Quebec	263	5	2016	0.80	4694	83.33		0.05	
Mattawin	Quebec	194	5	2016	0.24	4793	283.64		0.05	
Toulnustouc	Quebec	205	5	2016	0.56	4926	124.93		0.05	
Haut-Saint-Maurice	Quebec	194	5	2016	0.80	4942	87.74		0.05	
Olomane	Quebec	240	5	2016	0.80	4976	88.34		0.05	
Temiscamingue	Quebec	103	5	2016	0.52	5592	152.73		0.05	
Harricana	Quebec	822	5	2016	0.80	5743	101.96		0.05	
Nastapoca	Quebec	354	5	2016	0.79	6008	108.01		0.05	
Nalashquan	Quebec	559	5	2016	0.80	6474	114.93		0.05	
Sakami	Quebec	126	5	2016	0.29	6558	321.17		0.05	
Saint-Paul et Bujeault	Quebec	126	5	2016	0.78	7774	141.55		0.05	
Saint-Augustin	Quebec	148	5	2016	0.80	7823	138.88		0.05	
AUX FEUILLES ET PELADEI	Quebec	559	5	2016	0.78	10387	189.13		0.05	
Arnaud at Payne	Quebec	400	5	2016	0.67	11852	251.24		0.05	
ASHUAPMUSHUAN	Quebec	730	4	2006	0.70	4895	98.84		0.05	
BECANCOUR	Quebec	390	4	1993	0.70	4895	98.84		0.05	
BRISAY	Quebec	382	4	1993	0.70	4895	98.84		0.05	
CHUTES CHAUDIERES	Quebec	249	4	2000	0.70	4895	98.84		0.05	
GRANDE-BELEINE	Quebec	2058	4	2002	0.70	4895	98.84		0.05	
GRANDE-BELEINE	Quebec	915	4	2006	0.70	4895	98.84		0.05	
KIPAWA	Quebec	115	4	2006	0.70	4895	98.84		0.05	
LG-1/LaGrande	Quebec	620	4	1994	0.61	2529	58.88		0.05	
LG-1/LaGrande	Quebec	656	4	1995	0.61	2529	58.88		0.05	
LG-3/LaGrande	Quebec	2334	4	1990	0.61	2529	58.88		0.05	
MANIC	Quebec	67	4	1993	0.70	4895	98.84		0.05	
MANIC	Quebec	67	4	1994	0.70	4895	98.84		0.05	
MANIC	Quebec	602	4	1998	0.70	4895	98.84		0.05	
MANIC	Quebec	322	4	1999	0.70	4895	98.84		0.05	
MERCIER	Quebec	100	4	2000	0.70	4895	98.84		0.05	
NEW PLANT 18	Quebec	300	4	2008	0.70	4895	98.84		0.05	
NEW PLANT 5	Quebec	500	4	2006	0.70	4895	98.84		0.05	
NEW PLANT 6	Quebec	500	4	2008	0.70	4895	98.84		0.05	
OUTARDES	Quebec	828	4	2002	0.70	4895	98.84		0.05	
OUTARDES	Quebec	282	4	2007	0.70	4895	98.84		0.05	
RAPID DES COEURS	Quebec	348	4	2000	0.70	4895	98.84		0.05	
STE-MARGUERITE	Quebec	820	4	2002	0.70	4895	98.84		0.05	

APPENDIX B

DOCUMENTATION OF LEADTIME-SPECIFIC HURDLE RATES USED IN TO FORECAST ELECTRIC UTILITY FUEL CHOICE

1. Assumptions.

The objective of this section is to document the hurdle rates used the Electricity Capacity Planning (ECP) submodule of the Electricity Market Module (EMM) for the Annual Energy Outlook 1996 (AEO96). Utility aversion to long leadtime technologies is well known. To incorporate this aversion in the ECP, separate hurdle rates for technologies with different leadtimes were developed. This was done by estimating risk-premiums that were functions of leadtimes, and the longer the leadtimes, the greater would be the risk-premiums. These risk premiums were then subtracted from the overall cost-of-capital to derive leadtime-specific hurdle rates used for investment purposes.

The assumptions made in this analysis will first be discussed. Then, the methodology will be outlined. The reader is assumed to have a working knowledge of micro-economics and finance.

The first assumption deals with the nature of regulation. This analysis assumes the continuation of cost-based regulation. If utilities could recover all their operating and capital costs with certainty, all the risks are being shifted to ratepayers. Under such circumstances, in the limit, the appropriate costs and revenues would be discounted using a risk-free rate-of-return. However, over the last 15 years, the state Public Utility Commissions (PUCs) have disallowed excessive construction costs. Moreover, most commissions now have incentive programs that reward utilities for good performance and penalize them for poor performance. These programs shifted some risks from rate payers to shareholders.

Thus, full cost-recovery of all the operating costs is assumed, and, therefore, by assumption utility decision-makers will ignore all operational uncertainties. However, the PUCs are assumed to have a set of programs that shift all the construction-related risks and rewards to shareholders. Thus, this analysis will focus solely on the capital-related risks. This assumption favors natural gas-fired technologies.

Second, financial and economic theory states that the discount or hurdle rate used for investment decision-making purposes should equal the investment's cost-of-capital. If all the risks associated with building long leadtime technologies were completely diversifiable, the systematic risk and, thus, the cost-of-capital would not be a function of a plant's leadtime. This observation would suggest that the hurdle rates should be the same for short and long leadtime technologies. To estimate systematic technology-related risks, the correlation of the costs (and revenues) with the appropriate macroeconomic factors must be estimated. Such an endeavor is far beyond the scope of this project. The second assumption is that all the leadtime-specific risks are diversifiable, and, therefore the opportunity cost-of-capital will be the same for short and long leadtime technologies. This assumption favors long leadtime technologies.

However, when an uncertain investment is irreversible, the hurdle or discount rate used for capital budgeting will be greater than the opportunity cost-of-capital. More important, this wedge is a positive function of the absolute variance in costs. Thus, even if the cost-of-capital is assumed to be the same for long and short leadtime technologies, the hurdle rates could be different. This is valid if the absolute variance in the costs of long and short leadtime technologies are different. The reasons why this is true will now be discussed.

The cost data used in the ECP are actually forecasts. The longer a plant's leadtime, the longer will be the necessary forecasting horizon. That is, a plant that only takes one year to build will only require one year forecast of costs, demand, etc. However, to estimate the cost of a plant that takes seven years to build, 7-year forecasts are needed. The precision (variance) of any forecast decreases as the forecast horizon increases. Thus, the longer the leadtime, the greater would be the variability in the estimated cost, simply because longer forecast horizons are needed.

2. Methodology

The methodology consists of two steps:

1. Compute the variance in capital costs as a function of leadtimes.
2. Use the simplest model of investment decision-making under uncertainty to compute the wedge between the cost of capital and the hurdle rate. This wedge is a function of leadtimes.

Each of these steps will be discussed in turn.

Step 1: Compute the variance in capital costs as a function of leadtimes.

To do this, a "model" must first be developed that links the relevant causal factors to total estimated construction cost. To forecast total construction costs, the overnight costs, or the cost of building a plant at a single point in time is first estimated. However, it takes several years to build a power plant and, consequently, forecasted financing charges and forecasted increases in the prices of the labor and materials used to build the power must be included. The former is typically called "interest during construction" and the latter "escalation during construction." The sum of these two items is called the time-related costs. Total project costs can be computed by adding the overnight and time-related costs.

The longer the estimated construction duration, the greater will be the time-related and total capital costs. More important, the longer the estimated leadtimes, the greater will be the variance in the forecasted interest and inflation rates. Thus, the greater the leadtime, the greater would be the variance in the estimated time-related and total capital costs. Thus, interest and inflation rates are two causal factors considered in this analysis.

The variability in overnight construction costs is assumed to be invariant to a plant's leadtime. If longer leadtime technologies are more complex and difficult to manage, this assumption would

not be valid. There is some empirical evidence that the forecast errors in overnight nuclear construction costs are correlated with leadtimes. Since there were no similar analyses for other technologies, the variability in the overnight construction costs was not considered. Again, this assumption favors long leadtime technologies.

Additionally, if the utility over (under) estimates electricity demand, the value of that capacity would be less (greater) than otherwise would be the case. There are two reasons for this. First, PUCs might disallow some or all of the costs. Second, utilities can always sell the power to others and the value of the power would be less if there was excess capacity. Thus, the greater the variance in estimated demand, the greater would be the variance in value of the capacity. The third factor is the estimated demand for electricity.

Thus, the first step is to develop a model construction costs and the value of that capacity as a function of the following three factors:

1. Inflation rates
2. Interest rates
3. Demand for electricity

By introducing demand considerations, capital costs are adjusted for the need for the capacity. In the remainder of this paper, value-adjusted capital costs are being considered.

Step 1A-Link the levels of interest rates, inflation rates, and electricity demand to the level of costs.

The following equations were used to link total construction costs to the levels of interest and inflation rates. These equations are used in the EMM to compute total construction costs.

$$1) \quad TC = X \cdot \left[\sum_{t=0}^{t=T} P_t \cdot \left[\prod_{t=t-1}^{t=T} (1+r_t) \cdot \prod_{t=0}^t (1+i_t) \right] \right]$$

$$2) \quad P_t = t/T$$

where:

X = overnight construction costs

P_t = real cash outlays in year t of the construction period as a percent of the total number of years in the construction period T

i_t = the annual inflation rate in year t

r_t = the annual interest rate in year t

TC = total construction costs

To adjust construction costs for the need for the capacity, the following assumption was made. Equations 1 and 2 compute total construction costs. It was assumed that the value-adjusted construction costs would be proportional to the over(under) estimation of demand.⁶ That is, if demand was corrected estimated, the value of that capacity would equal its costs. If, however, demand was overestimated (underestimated) by 10 percent, the value of that capacity would only be 90 (110) percent of the costs. Thus, total value-adjusted capital costs, TRC, is given by the following:

$$3) \quad TRC = TC * (rdemand / edemand)$$

The variables rdemand and edemand denote the realized and estimated demand respectively and, thus the ratio is a measure of the forecast error. For example, if estimated demand in some future year was 10 gigawatts and realized demand for that year was only 9 gigawatts, the ratio would be .9. As a result the value of that capacity would be 90 (110) percent of its costs.

Step 1B. Compute the variance in total costs as a function of the variance in interest rates, inflation rates, and forecast errors in demand.

Equations 1-3 represents the basic "model" used. Equations 1 and 2 shows the link between interest and inflation rates and total capital costs. Equation 3 shows total value-adjusted construction costs as a function of the forecast error in demand. These three equations were included in a LOTUS 123 spreadsheet and the Monte Carlo simulation LOTUS add-in, @RISK, was used to compute the variance in total value-adjusted costs.

The necessary inputs for the Monte Carlo simulations are assumptions about the distributions of the variables of interest. This, in turn, requires assumptions about the means and variances in interest rates, inflation rates, and demand. Interest and inflation rates were assumed to be normally distributed with means of 5 and 12 percent, respectively. The mean value of the ratio of edemand and rdemand was 1. That is, on average estimated and realized demand were assumed to equal each other.

The basic idea behind this entire analysis is that variances increase as forecast horizon increases. For a technology with a 1- year leadtime, it is only necessary to forecast interest rates, inflation rates, and electricity demand for one year. If another technology has a 4-year leadtime, one must

⁶As will be noted below, the simplest model of investment decision making under uncertainty was used. The methodology just described is the only way to introduce demand considerations into this simple model.

forecast the variables of interest for four years. Crucially, the variance in 1-year forecast will be less than the variance in a 4-year forecast (i.e., the 1-year forecast will be more precise than a 4-year forecast). The variances in the three variables were constructed to be roughly consistent with a geometric Brownian-motion stochastic process. The underlying variances were based on historical data. One property of this stochastic process is that the variances increase over time.⁷ The 90 percent confidence intervals for the three variables of interest as functions of the length of the forecasts are shown in Table 1. Since only three leadtimes were considered (3, 5, and 7 years), the estimated forecast errors were just computed for 3, 5, and 7 year forecasts of demand.

For example, Table 1 shows that the 90 percent confidence intervals for the ratio of r_{demand} and e_{demand} for a 3-year forecast were .96 and 1.04, respectively. Thus, roughly speaking, there is a 90 percent probability that the ratio of the realized to estimated demand forecasted three years in the future is between .96 and 1.04. However, similar 90 percent confidence intervals for a 7-year forecast were .88 and 1.12. Given the forecast errors in electricity demand made in the 1980s, the estimates shown in Table 1 are extremely conservative.

Table 2 shows the mean total value-adjusted capital costs, based upon an overnight construction cost of \$1. This value was chosen to be consistent with the theory discussed in the next section. This table also shows the 90 percent confidence intervals and the variances errors. As expected, the precision of the cost estimates decreases as leadtimes increase. This is because the precision of any forecast decreases as the forecast horizon increases. Stated differently, because the precision of any forecast decreases as the forecast horizon increases, longer leadtime technologies will be more risky.

Step 2: Compute the wedge between the cost-of-capital and hurdle rate as a function of the variance in the capital costs.

First-year economics and finance students are often taught to use the cost-of-capital as the hurdle rate for capital budgeting problems. However, modern theory of investment decision-making under uncertainty states that, if an investment is irreversible, there will be a "wedge" between the cost-of-capital and the appropriate hurdle rate. This wedge is a positive function of the variance in costs (and prices).

A very general model with relatively few restrictive assumptions is being developed to compute that wedge. This research is, however, not complete, and thus, for the AEO96, a simple and restrictive model is used.⁸ According to this model, the wedge, γ , between the opportunity cost-of-capital, μ , and the hurdle rate, ρ , is:

⁷The theory used below also assumes this stochastic process.

⁸See, McDonald R. and Siegel, D., "The Value of Waiting to Invest," Quarterly Journal of Economics, November 1976. As noted above, because this model was used, demand considerations were incorporated in an ad hoc manner.

$$Y = \frac{\varepsilon}{\varepsilon - 1}$$

$$\varepsilon = \sqrt{\left(\frac{\alpha_v - \alpha_f}{\sigma^2} - \frac{1}{2} \right)^2 + \frac{2(\mu - \alpha_f)}{\sigma^2} + \left(\frac{1}{2} - \frac{\alpha_v - \alpha_f}{\sigma^2} \right)}$$

$$\sigma^2 = \sigma_v^2 + \sigma_f^2 - P_{vf} \sigma_v \sigma_f$$

$$\rho = Y\mu$$

where:

- σ_f = the standard deviation in the expected operating costs;
- σ_v = the standard deviation in the expected capital costs;
- α_f = the change over time in the mean operating costs;
- α_v = the change over time in the mean capital costs;
- P_{vf} = the correlation between the changes in operating and capital costs.

The risk premium would be $\rho - \mu$.

For simplicity, it was assumed that all the costs were constant over time. Thus, α_f and α_v would equal zero. Additionally, since the operating costs were assumed to be recoverable, from the utility's viewpoint, σ_f , and P_{vf} were assumed to equal zero. The opportunity cost-of-capital was assumed to be .07. The resulting risk premiums are shown in Table 3.

Table 1. 90 Percent Confidence Intervals for the Three input Variables

Forecast Errors in Demand

Length of Forecast (In Years)	90 Percent Confidence Intervals
3	.96 - 1.04
5	.92 - 1.08
7	.88 - 1.12

Note: See text for discussion about the units

Inflation Rates (in Percent)

Length of Forecast (In Years)	90 Percent Confidence Intervals
1	4.8 - 5.1
2	4.6 - 5.4
3	4.4 - 5.6
4	4.1 - 5.9
5	3.8 - 6.2
6	3.6 - 6.4
7	3.3 - 6.7

Interest Rates (in percent)

Length of Forecast (In Years)	90 Percent Confidence Intervals
1	11.8 - 12.2
2	11.4 - 12.5
3	11.0 - 13.0
4	10.7 - 13.3
5	10.4 - 13.6
6	10.0 - 14.0
7	9.6 - 14.4

Table 2. Mean, Variance, and 90 Percent Confidence for Total Construction Costs

Leadtime (In Years)	Mean	Variance	90 Percent Confidence Interval
3	1.31	.00152	1.26 - 1.37
5	1.56	.00844	1.42 - 1.67
7	1.84	.02560	1.61 - 2.05

Note: Total costs based on overnight cost of \$1.

Table 3. Estimated Risk Premiums (in percent)

Leadtime (in Years)	Cost-of-capital	Hurdle Rate	Risk Premium
3	.07	.0776	.0076
5	.07	.0890	.0190
7	.07	.108	.0380

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