EE 590F Course Project, Due Dec 12, 2008

A. Transmission Planning: The objective of Part A of this project is to design a least-cost transmission 30-year plan for the US capable of moving electric energy from the wind-intense regions to major load centers. Although it represents an "extreme" scenario, it offers a "data point" that may well characterize upper-bound needs for major transmission infrastructure investments. You should use Plexos. The following information is given to help guide you.

1. You should read the AEP article, "Interstate Transmission Vision for Wind Integration," available on the course website. This article, at its end, illustrates a possible design. In designing your own transmission system, you might *consider* the AEP design and the reasons for its configuration.
2. Data on available transmission technologies are given in Table 1 below. Blanks indicate either "not applicable" or that no data was identified. You may have access to additional or alternative data, and if you do, and if you trust it, feel free to use it. Alternatively, if you need data not given below and can find no sources, you may estimate it.

Table 1

Equipment	X (AC) or R (DC) (Ω/mile)	SIL** (MW)	HVDC Rating (Mw)	Cost (million$)/mile	Cost
69 kV sngl cct (SC)		9-12			
69 kV HSIL		10-40			
138 kV SC		40-50			
138 kV HSIL SC		50-120			
230 kV AC SC		120-130			
230 kV AC HSIL SC		130-440			
345 kV AC SC		390		1.59*	
345 kV AC dble cct (DbC)				2.65*	
500 kV AC SC	0.5925@	1000		1.8*	
500 kV AC DbC				3.38*	
500 kV AC HSIL SC, 6bdl	0.5£	1300 !		2.0*	
500 kV AC HSIL DbC, 4bdl		1100 !		2.5*	
765 kV AC, SC, 4bdl	0.5069€	2250		2.86*	
765 kV AC, SC, 6bdl	0.4724€	2250		3.3*~	
765 kV AC HSIL SC	0.4£	4000		4.32*	
1100 kV AC SC	0.4787@	5180>|			
500 kV DC converters+					$131/kW<|
500 kV DC Line	0.0129 (/pole)		2400	1.8	
600 kV DC converters+					$200/kW
600 kV DC Line			3150/	2.03*^	
800 kV DC converters+					$250/kW
800 kV DC Line			6400	3.62*^	

* 2008 dollars. +Bipole configuration assumed, with converter costs including both poles at both ends of line. ^ Estimates based on the rule of thumb that the cost of a DC transmission line may be 80% to 100% of the cost of an AC line whose rated line voltage is the same as the rated pole-to-ground voltage of the DC line. @These estimates came from 1984 paper by Scherer & Vassell. ~These estimates came from AEP planning engineers. ! Data came from slides by A. Dariani, Canada. >| These estimates came from the 1979 AEP paper by Dunlop, Gutman, and Marchenko. /This data comes from existing 600 kV line in Brazil (Itaipu). <| These costs came from presentation by ABB engineer Michael Bahrman. €These were computed based on: 4bdl – 1.5' diam bdl, Dipper - between Pheasant and Bobolink (X_a=.045), 45' phase spacing (X_d=.4619); 6bdl – 2.5' square bdl, Tern (X_a=.0105.), 45' phase spacing (X_d=.4619). £ Estimated by Dr. McCalley. **SIL for double circuit lines is for one line only, and so capacity estimates should be based on twice the given amount.

3. Assume that each AC substation requires 1 transformer, and also, for each line terminating at the substation, 1 circuit breaker. Transformer and circuit breaker costs are given in Table 2 below. Costs for 345, 500, and 765 kV circuit breakers and transformers are taken from the 1990 Panel-Working Group paper on AC-DC economics chaired by Diemonds (escalated to account for inflation, given in 2008 dollars). All other costs are estimated.

Table 2

	345 kV	500 kV	765 kV	1100 kV
Circuit breakers	$1.07 million	$2.14 million	$2.71 million	$4.5 million
Transformer	$5million	$6.4 million	$8.5million	$12 million
Voltage control eqpmnt	$2.6 million	$3.3 million	$4.0 million	$6 million

4. Initial year 2008 national peak load, 810 GW, is allocated by region as shown in Table 3 below. Initial year 2008 national generation capacity, 909 GW, is also allocated by region in the Table. In addition, percent capacity among fuels is also indicated by region. This data comes from the NERC 2007 Long-Term Reliability Assessment, with exception of the Western Systems data, which is adapted from the PhD dissertation by A. Quelhas, (ISU, 2006).

Table 3

Region*	Peak Load (GW)	Capacity (GW)	Percent of Capacity For Each Generation Technology						
			Nuclear	Coal	NGCC+	CT+	Hydro **	Wind	Oil
Total	810	909							
1.ERCOT	67	72	7	22.1	55.1	10.1	1.1	0.3	5
2.FRCC	48	54	8	19.5	41.5	8.5	0.1	0	22.5
3.MRO	44	50	8	66.5	13.5	7.4	7.5	0.3	8
4.NPCC	64	70	14	9.3	36.3	8.4	12.4	0.04	18.4
5.RFC	190	214	15	48.1	20.1	7.1	3.0	0.04	7
6.SERC	210	230	16	44.1	17	6.3	10	0	7
7.SPP	44	49	1.4	43	39.9	7	4.7	0.01	4
8. NW	53	63	2	20	6.6	3.7	67	0.7	0.2
9. CAL	51	60	8.3	1	46.4	13.8	26.9	2.8	1.5
10. SW	25	29	14.8	38.4	23.4	7	16	0	1
11. RM	15	18	0	67	13	5	10	1.1	1.3

*Only Continental US load and capacity data included in this table, i.e., no Canadian or Mexican load or capacity is included, and Hawaii & Alaska are excluded. ** Includes pumped storage. +The NERC data specifies all natural gas-consuming technologies under the single category of "Gas," which is the total of CT and NGCC here. Thus, the total is considered to be "accurate" whereas the split is an estimate.

5. The regions listed in Table 3 are shown in Fig. 1. Assume all load and generation for each region are located at a single node in the middle of the square identifying the region's number.

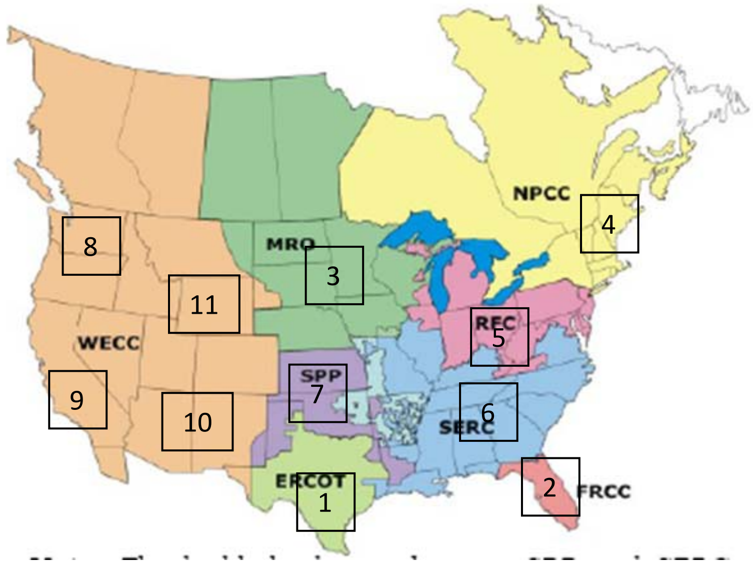

Fig. 1

6. The various generation technologies have the following data.

Table 4

Technology	Data Values		
	Heat Rate MBTU/MWhr	Investment Cost $/kW	Emission Rate lbs CO_2/MBTU
	10.4	2475	0
Pulverized Coal	9.2	1534	215
NGCC	7.5	706	117
CT	10.8	500	117
Hydro	0	N/A	0
Wind	0	1434	0
Oil	10.1	N/A	162
IGCC	8.765	1733	199
IGCC w/CarbSeq	10.781	2537	20
Solar	0	5649	0

7. Locationally variable data, for fuel prices and for wind/solar capacity factors, are given in Tables 5 and 6. These data can be assumed to remain constant through time (an assumption worth exploring for fuel prices).

Table 5

Region	Fuel Prices, $/MBTU			
	Coal	Natural Gas	Uranium	Oil
1.ERCOT	1.90	7.00	0.75	12.00
2.FRCC	1.95	8	0.75	12.00
3.MRO	1.80	8	0.75	12.00
4.NPCC	1.90	9	0.75	12.00
5.RFC	1.80	8.5	0.75	12.00
6.SERC	1.85	8	0.75	12.00
7.SPP	1.80	7.5	0.75	12.00
8. NW	1.80	8	0.75	12.00
9. CAL	1.95	8	0.75	12.00
10. SW	1.80	8	0.75	12.00
11. RM	1.70	8	0.75	12.00

Table 6

Region	Capacity Factors									
	Wind					Solar				
	50	40	30	20	10	25	22	20	15	10
1.ERCOT		x						x		
2.FRCC			x				x			
3.MRO	x								x	
4.NPCC			x						x	
5.RFC			x						x	
6.SERC					x			x		
7.SPP		x						x		
8. NW		x								x
9. CAL			x				x			
10. SW				x		x				
11. RM		x							x	

8. Assume an annual load growth of 1.5% for all areas. A file is provided on the website that contains the 30 year load at each node.
9. Assume there is no existing transmission interconnecting the regions at the initial 2008 year. This assumption can be interpreted to indicate that although existing transmission will be used to perform inter-regional transfer for 2008 load levels, it will not be used to perform inter-regional transfer for additional load above 2008 levels.
10. Design a transmission system over a 30 year period that will accommodate the following:
    - Non-wind generation is replaced at a rate to exactly compensate for retirements of non-wind generation. Thus, you can assume non-wind generation capacities do not change over the entire 30 year period, so that all load growth is compensated only by wind growth.
    - Assume storage technologies for wind farms (pumped storage, compressed air, hydrogen generation for fuel cells) mature enough so as to model wind capacity factors at ~~40%~~ the values given in Table 6, and capacity credit at 25%. Note that capacity credit is used as follows:

      Reserve=0.12=(Σ Cap_i -Load)/Load
      For all units except wind, Cap_i=Unit Capacity
      For wind units, Cap_i=(Capacity Credit)*Unit Capacity

    - The national grid must maintain a 12% reserve (total capacity must be 12% greater than peak load).
    - Every unit of national wind growth is split between the regions according to Table 7:

Table 7

Region	%
1.ERCOT	10
2.FRCC	5
3.MRO	25
4.NPCC	9
5.RFC	9
6.SERC	4
7.SPP	20
8.NW	5
9.CAL	6
10.SW	1
11.RM	6

- Your transmission system must meet the following requirements:
  a. Its cost should not exceed $60 billion (the cost of the AEP plan); the lower, the better.
  b. Emergency operation is defined by loss of one AC line or bipole loss of one DC line. Flows for 150 mile-long AC lines must be within 1.0 SIL under normal conditions and 1.5 SIL under emergency conditions. Lines significantly shorter or longer than 150 miles should have their ratings adjusted based on the Fig. 2 left-plot for lines of voltage class 500 kV or less, and based on the Fig. 2 right-plot for lines of voltage class 765 kV or above. These plots came from the 1979 AEP paper by Dunlop, Gutman, and Marchenko. (Substation placements incur significant costs, per the data in Table 2 above; however, voltage control devices, which can only be placed at substations, have the effect of terminating the line, limiting the length, and therefore preventing line capacity reduction characterized by Fig. 2.)

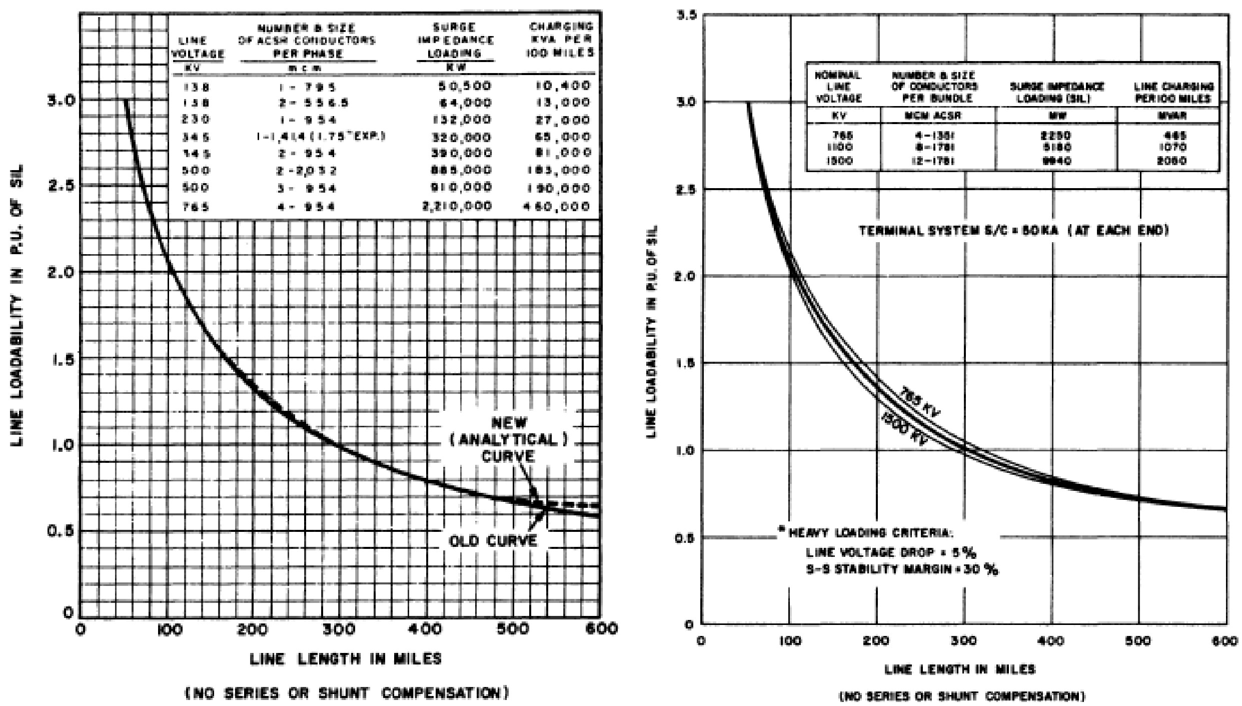

Fig. 2

11. You should turn in the following:
    - A summary of the data you used together with the source of each data item. If any data was estimated without a source, indicate as much. Provide reasoning supporting your estimate.
    - One or two tables summarzing by year the peak load and wind generation capacity for each region.
    - Identification of new transmission to be built (type, distance, capacity, sub locations), & when.
    - The net-present value of all costs associated with your design.
    - A one-line diagram illustrating your design.
    - Post-contingency flows for all N-1 transmission contingencies for at least the last year.
    - A discussion of the strengths and weaknesses of your design.

B. Gen/trans planning: The objective of Part B is to design both the generation and transmission for a least-cost power grid for the US. That is, you need to identify the least cost expansion plan for both generation and transmission. In addition to the generation technology data and fuel price data, you will need to make an assumption on carbon tax. Plexos can do this for you if you enter all the data.

A guide for using PLEXOS to accomplish part A:

1. Build 11 regions and 11 nodes, one for each region. Select “Minimum capacity reserve” for “Configuration” menu and set it as 12%.

2. Attach the 11 load files to the regions. You will find the load files (one for each region) on the desktop when you remote login to the Plexos server.

Build 11 “data file” objects. Connect load files to data file objects. Then assign these data file objects to each region.

3. For each region, build 7 basic generators. The capacity of the generators should be the capacity of different generation technologies in that region. Fill in all of the data we have about generators. Remember to set the capacity factors for wind generator.

4. Build another wind generator in each region. In “configuration” menu, select “Maximum capacity” and set it as a dynamic value by selecting the box in front of “Dynamic Property”. Build 11 “data file” objects, and connect the 11 generation capacity data files to them. Then In the “Properties” window of the new wind generator, edit its “Maximum capacity” like below:

	Property	Value	Units	Band	Date F	Date Tc	Timeslice	Data File
	Max Capacity	0	MW	1				
*		0		1				Gen capacity 1

In this way, the capacity of wind generator can by specified by the data file. You will find the 11 generation capacity data files on the desktop.

5. The transmission planning part is similar with the generation expansion planning that we have done before. Just enter build cost, Reactance/Resistance, Max flow, Min flow, units (should be 0 in the beginning), Maximum units built, WACC, and Economic life. You can put different lines between to nodes and let PLEXOS choose the most economical one for you.

Note: If you can’t find a property mentioned above or in the HW assignment, go through the “Configuration” menu.