

**Chronological data:**

Figure 1 is included for interest, with all 30 house's consumption plotted, and the heavy black line indicating the *average* of the residential demand.

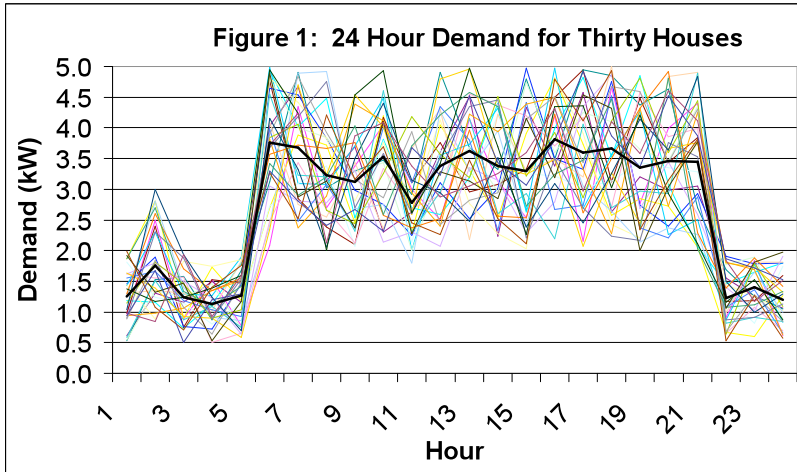
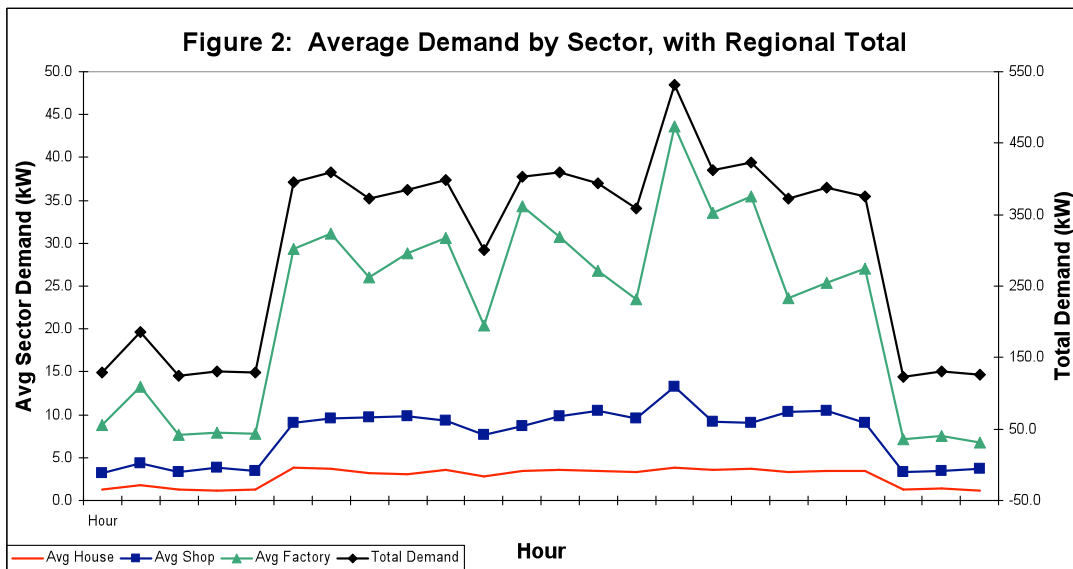


Figure 2 plots the average demand for each sector or category, along with the total demand from all 50 customers. Note that the sector averages are plotted against the left-hand axis, while the total demand is plotted against the right-hand axis. The coincident peak occurs at hour 16, at a value of 531.4 kW. Note that in this data, each sector peaks at this time, though if you scan the data for each of the 50 individual customers, you will see that not every customer consumes her/his most electricity during hour 16. The significance of the coincident peak is

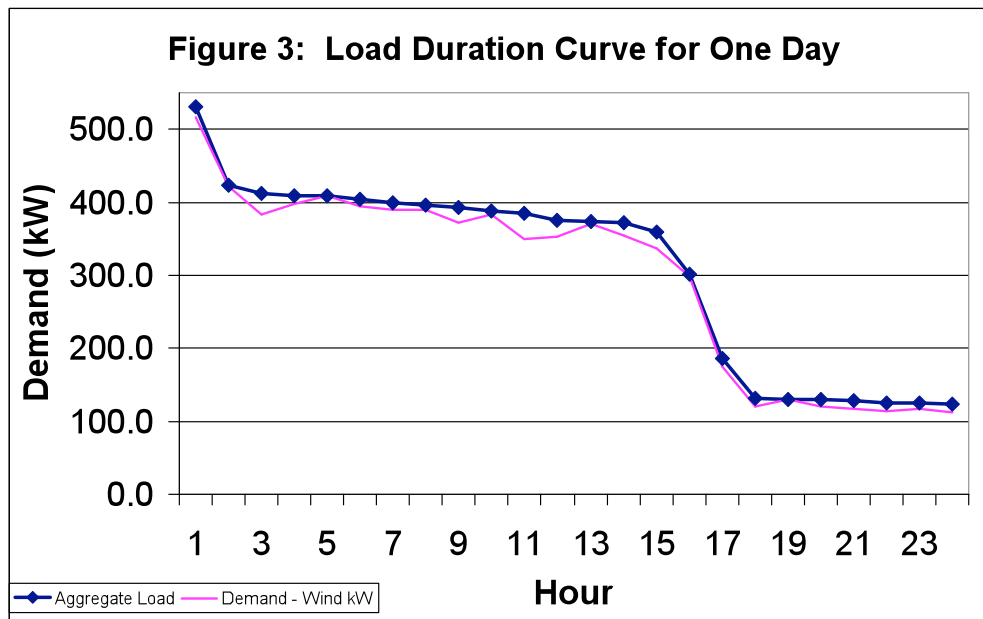
- (i) that it is *not* the sum of the individual peak demands, since they occur at different times. If you identify the peak demand from each customer and sum these, for the data given, you would find this value to be 599.8 kW. The actual peak experienced by this system is 531.4, which is 11% less than the 599.8 value.
- (ii) it is the peak demand experienced by the system, and so indicates to the company supplying electricity the maximum demand they will be expected to serve.



**Figure 3: Original and net-wind Load Duration Curves**

a\_i) The peak demand, as for the chronological data, is 531.4kW. As discussed above, this is the capacity that the power company must build in order to serve the 50 customers represented by the data. (Note that in reality, to maintain system reliability, the power company will ensure a certain “reserve margin” above the peak value, of between 10% and 15%, in most cases).

a\_ii) The total energy consumed is 7406.7kWh, or 7.4 MWh. This amount indicates the amount of fuel the power system will need to purchase, in order to burn this fuel to generate electricity. If renewable resources, such as hydro, wind or solar energy are used, then this indicates the amount of energy resource needed from these sources, in combination with fossil fuel purchases.



b) For part (b), you can select any plants you want to build, in order to serve the demand indicated by the LDC above. One approach would be to assume one baseload plant, one intermediate plant and a peaking plant in order to have the total capacity add up to the peak of 531.4kW + some reserve margin. An actual company would build capacity above the peak demand to have a reserve margin necessary for system reliability.

The actual selection of plants follows our class discussions and in-class activities with the screening curve. Typical baseload plants are nuclear, hydro and some coal. Intermediate plants tend to be coal and gas-fired plants (steam cycle), and peaking units tend to be combustion turbines (fired by natural gas but using a gas thermodynamic cycle, not a steam cycle). Review the class notes if you are unclear as to why these types of plants fill their respective baseload-intermediate-peaking roles.

Using the data provided to construct the screening curve, you need to determine the fixed cost in \$/kW/year (which would more normally be \$/MW/year of course), for the y-axis intercept value. Then use the variable O&M for the slope of the cost line for each technology. The fixed costs are the (levelized capital costs + fixed O&M). These numerical values are given in \$/MWh (per year), so to convert to \$/MW you must multiply by the

number of hours. Then you must also convert to your desired capacity increment, for building plants of either 50kW, or 100kW, or whatever size you wanted to assume.

Plant Type	Capacity Factor (%)	Annual capital cost for 100kW plant	Annual capital cost for 50kW plant	U.S. Average Levelized Costs (2008 \$/MWh) for Plants Entering Service in 2016				
				Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	\$54,356	\$27,178	69.2	3.8	23.9	3.6	100.4
Advanced Coal	85	\$64,408	\$32,204	81.2	5.3	20.4	3.6	110.5
Advanced Coal with CCS	85	\$73,641	\$36,820	92.6	6.3	26.4	3.9	129.3
NGas								
Conventional CC	87	\$18,748	\$9,374	22.9	1.7	54.9	3.6	83.1
NGas Advanced CC	87	\$18,291	\$9,145	22.4	1.6	51.7	3.6	79.3
NGas Advanced CC with CCS	87	\$35,439	\$17,719	43.8	2.7	63	3.8	113.3
NGas								
Conventional CT	30	\$12,036	\$6,018	41.1	4.7	82.9	10.8	139.5
NGas Advanced CT	30	\$11,195	\$5,598	38.5	4.1	70	10.8	123.5
Advanced Nuclear	90	\$84,043	\$42,022	94.9	11.7	9.4	3	119
Wind	34.4	\$42,459	\$21,230	130.5	10.4	0	8.4	149.3
Wind - Offshore	39.3	\$63,242	\$31,621	159.9	23.8	0	7.4	191.1
Solar PV	21.7	\$72,843	\$36,422	376.8	6.4	0	13	396.1
Solar Thermal	31.2	\$67,289	\$33,645	224.4	21.8	0	10.4	256.6
Geothermal	90	\$87,434	\$43,717	88	22.9	0	4.8	115.7
Biomass	83	\$59,911	\$29,956	73.3	9.1	24.9	3.8	111
Hydro	51.4	\$48,268	\$24,134	103.7	3.5	7.1	5.7	119.9

### Demand Management

For this problem, you would implement one or more demand *response* or demand *management* programs as we discussed in class, such as peak-shifting, peak shaving, and energy conservation, that you could target to certain hours of the day in order to achieve differences in the LDC in the desired places. For example, you could target all hours, which would target baseload plants, peak demand hours which would target peaking generating units, and/or the bulk of the hours in the middle of the day which would target the intermediate type of generating plant.

### Wind generation

- The **net LDC** is shown above in figure 3. Note that you need to construct the net LDC by first subtracting the wind generation from the total demand on an hour-by-hour basis (using the data in its chronological format), and then constructing the new LDC. In this way you line up the peak wind generation with the actual demand level at that peak hour. It is very rare in actual systems to have the peak wind generation occur at the exact moment of peak electrical demand (which is why the ‘capacity credit’ value is typically less than the installed capacity of the wind farm).
- The **energy capture** from the windfarm is 280kWh. The energy capture will result in lower fossil fuel purchases – a benefit to the system.
- The **capacity factor** needs to be estimated. The maximum output from this farm is 34kW, so we could perhaps assume a maximum capacity of 35kW. If the wind farm generated 35kW each hour for 24 hours, the total energy capture would be

840kWh. Instead, we have only 280kWh. Thus the capacity factor (the ratio of these two values) is 33%.

- The emissions displacement of course depends upon which generating technologies you decided to build above, and so which are available to be displaced and so emit lower GHGs (greenhouse gases).
- It appears that most of the energy is generated during the “intermediate” hours – or the hours when an intermediate category of generating plant would be dispatched. Therefore, during these hours, when the wind was generating, the most expensive plant we would *otherwise* need to dispatch, will be ***displaced*** – will not be used.
  - This plant will be an intermediate plant for 15 hours (those identified on the LDC as data points number 2 through 16). The average energy capture during these hours is about 13kW per hour.
  - Alternatively, we can look at the peak hour and we see that the wind farm generates about 15kW during this hour. This value is typically defined to be the ***capacity credit***.
  - Therefore, we could argue that the wind farm displaces 13kW of intermediate capacity, and/or that it displaces 15kW of peaking capacity. → This is seen as a benefit to the system – needing to build less generating capacity as we build more wind farms. *This is not an exact science!* Deciding how much capacity is displaced, in a meaningful way such that the power company does not need to build traditional or conventional generating units, is very controversial (because, with wind being a stochastic/intermittent resource, it is hard to convince power system operators that they can depend upon the wind when they need it).
- If I could control the wind – I would use demand response programs to
  - Knock off the peak such that the wind farm + DSM would displace the most capacity during the peak hour – so that the utility would not need to ever build this capacity.
  - I would also like to implement DSM during lulls in wind energy generation, *i.e.*, hours 4, 11, 13, and 18. I would use the DSM to help provide a smooth transition between the two adjacent windy hours, so as to provide a steady, rather than spastic, supply of energy to the system. This would make it much easier for the system operators to integrate the wind energy into their operating strategies.

### **Economic Dispatch**

To include wind generation in the economic dispatch formulation, you can either include the wind as a regular generator, or include it as essentially negative demand.

- As a generator it has non-typical characteristics because the variable O&M, which is typically mainly fuel cost, is essentially zero for wind (there is some wear and tear from operating that is not a fuel cost and is non-zero, but it is very small compared to other technologies’ fuel costs).
- This suggests putting wind generation in as negative load, which means you alter the energy balance constraint equation by making the total demand,  $P_D$ , a net-demand, after subtracting the assumed wind generation.

For demand response, you simply alter the energy balance constraint by subtracting the assumed amount of response demand from the original demand value,  $P_D$ .