A screening model for long range planning at the pool level

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A SCREENING MODEL FOR LONG RANGE PLANNING AT THE POOL LEVEL

by

R. Edahl, N. Tyle and S.N. Talukdar

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ABSTRACT

This paper develops a multi-period, multi-utility model for analyzing macro effects over extended horizons of 20 to 40 years. Plants are aggregated into categories and lumped at load centers, which may be interconnected by lossy lines. There may be more than one load center per utility. The generation, transmission, and operation planning problems for this set of load centers are formulated as a linear programming problem. A decomposition and means-end analysis method is used to solve the problem. The results are useful for minimizing macro effects, generation expansion by plant category; control technology retrofits; changes required in tie line capacities; long-term, inter-utility energy exchanges; long-term fuel scheduling; and the impacts of bubble constraints on emissions such as SO₂.

1. INTRODUCTION

The running of a utility involves collaboration with other utilities. Activities contributing to, and factors affecting, these collaborations include:

- remote siting and sharing of generating plants.
- inter-utility energy flows.
- bubble constraints on emissions (ceilings on the total emissions produced by the plants in a region that could encompass several utilities). Though such constraints are not now in effect, they are being seriously considered by regulatory bodies and could soon be adopted.

The possibility of collaboration increases the number of alternatives available to planners. For instance, some of the alternatives available to reduce the total SO₂ emissions produced by a utility are: (1) switch to lower sulfur fuels, (2) retrofit the coal burning plants with scrubbers, and (3) purchase energy from other utilities. To determine the optimal mix of these alternatives over an extended time horizon, one needs to simultaneously consider all the utilities that could collaborate over the entire horizon. This, of course, results in a very large optimization problem. To make it computationally tractable, we have adopted the following measures:

- aggregation to reduce the number of variables.
- representation of all the relevant phenomena by linear models so that the overall problem becomes one of linear programming.

The net result of this approach is a screening model, that is, a model that provides a comprehensive, but relatively undetailed, view of the activities of multiple, interacting utilities over multiple time periods. The most natural application of the screening model is to power pools because pools are the natural units interacting among utilities. But the model can also be applied to other groupings of utilities. In fact, since it works off a database that contains information on all the generating units in the continental US, it can be applied to any subset of the generating units.

In function, the screening model is best suited to providing inertia of the activities of utilities. These outputs can be used for high-level decision making or to provide inputs, targets, and guidelines for more detailed planning models that consider only one utility at a time. The alternatives to using screening models are either to treat utilities as if they were independent with no interactions, or to guess the interactions in advance. Neither is an attractive alternative.

The remainder of the paper is organized as follows. Section 2 formulates the linear programming problem. Section 3 describes the decomposition and means-end analysis used to solve the linear programming problem. Section 4 presents an example.

2. FORMULATION OF THE LINEAR PROGRAMMING PROBLEM

2.1. Assumptions

1. The net exports of electrical energy from the group of utilities considered to the rest of the country are known in advance.
2. Operating costs and emissions are linear functions of operating level of generating plants and pollution control technologies.
3. Capital costs for both generating plants and pollution control technologies are linear functions of their sites.
4. Plants are aggregated into 10 categories.
5. Fuel constraints for each plant category are aggregated into at most 3 categories.
6. Load demand points are aggregated into load centers.
7. Transmission losses between load centers are linear functions of power flow.
8. Retirement years of generating units are known in advance.
2.2. The Model

The multi-period multi-utility planning (MUP) problem is formulated as a linear programming model using aggregated, rather than the individual, plant and fuel categories. Instead of directly solving the problem as a single linear programming problem, which is potentially unmanageable, the problem is handled instead by a heuristic decomposition technique.

The MUP problem is defined as:

Given:
1. A time horizon divided into several periods.
2. The demand in each utility for each period, given in the form of a load curve.
3. The cost, availability, heating rate and pollution content of a set of representative fuels for each utility in each period.
4. The cost and other characteristics of a limited number of types of generating plants for each utility in each period.
5. The costs, efficiencies and other characteristics of a set of pollution control technologies for each utility in each period.
6. The transmission lines between the utility nodes, their capacities and loss characteristics in each period.
7. The emission caps for individual utilities and/or the caps for the whole region (merging the many utilities).

Find:
1. The inter-utility energy transfers in each sub-period.
2. The type, timing, size and location (by utility) of generation expansions and pollution control retrofit.
3. Utility emission caps, if they were not specified in the input. Also, the marginal cost of SO2 abatement.
4. The types and amounts of the fuel used in each period and each utility.

The problem is formulated as a Linear Programming (LP) problem.

2.3. Notation

The terms used in the linear programming formulation are defined below:

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>i</td>
<td>Type of generating plant/CT plant</td>
</tr>
<tr>
<td>j</td>
<td>Fuel type (j b removed if no fuel selection b allowed, e.g. nuclear plants)</td>
</tr>
<tr>
<td>n</td>
<td>Utility in the region</td>
</tr>
<tr>
<td>t</td>
<td>Time period</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Generating Plant Characteristics for utility n</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{i,n}$</td>
</tr>
<tr>
<td>$P_{i,n}$</td>
</tr>
<tr>
<td>$\Delta V_{i,n}$</td>
</tr>
<tr>
<td>$CF_{i,n}$</td>
</tr>
<tr>
<td>$\epsilon_{i,n}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Control Technology Characteristics for utility n</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V_{i,n}$</td>
</tr>
<tr>
<td>$U_{i,n}$</td>
</tr>
<tr>
<td>$X_{i,n}$</td>
</tr>
<tr>
<td>$r_{i,t}$</td>
</tr>
<tr>
<td>$k_{i,j,n}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Exogenous Variables</th>
</tr>
</thead>
<tbody>
<tr>
<td>$d$</td>
</tr>
<tr>
<td>$L_{m,n}$</td>
</tr>
<tr>
<td>$h_{m}$</td>
</tr>
<tr>
<td>$T_{h}$</td>
</tr>
<tr>
<td>$\omega_{n}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Regional emission constraint in period t (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$E_{r,n}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Decision Variables for utility n</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{i,n}$</td>
</tr>
<tr>
<td>$\delta_{i,n}$</td>
</tr>
<tr>
<td>$x_{i,n}$</td>
</tr>
</tbody>
</table>
Aetna! CT atifisasioa ia period t (tons of SO,
removed)

\[ O_{\text{atf}} \]

Power outflow from atifity r to atifity a ia a
segment s. of the load-duration curve

1.4. Linear Programing Formalizations

The following form of the MUP problem applies to a
region containing N atifities and for an extended planning horizon
(typically 20 to 40 year in length). The horizon is divided into
periods and the load curve for each period is divided into segments.
Then the total print worth of all capital and operating expenses
in all the atifities in the region is minimized over the
horizon to yield:

Minimize \[
E E V_{\text{atf}} + \sum_{i,j} \gamma_{i,j} \sum_{k=1}^{T} R_{i,k} - P_{i,k}
\]

subject to:

1. Demand constraints (generation should be at least equal to
demand):

\[ \sum_{i,j} \gamma_{i,j} - \sum_{r \neq a} O_{\text{atf}} - \sum_{r \neq a} O_{\text{atf}} \geq L_{\text{atf}} \]

for all m, t, a

2. Generation constraints (generated power should not exceed
power capacity):

\[ AV_{i} \sum_{k=1}^{T} R_{i,k} - \sum_{j} \gamma_{i,j} \geq AV_{i} \sum_{k=1}^{T} R_{i,k} - P_{i,k} \]

for all i, m, t, a

3. Capacity factor constraints (generated energy should not
exceed energy capacity):

\[ CF_{i}(Th) \sum_{k=1}^{T} R_{i,k} - \sum_{j} \gamma_{i,j} \geq CF_{i}(Th) \sum_{k=1}^{T} R_{i,k} - P_{i,k} \]

for all i, t, n

4. CT (Control Technology) constraints (CT usage should not
exceed capacity):

\[ \sum_{k=1}^{T} \gamma_{i,j} - \sum_{j} \gamma_{i,j} \geq E_{r} X_{\text{atf}} \]

for all i, t, a

5. CT constraints (CT cannot remove more SOx than is
produced):

\[ \sum_{m} \gamma_{i,j} \sum_{k=1}^{T} R_{i,k} - P_{i,k} \leq 0 \]

for all j, i, a

6. Regional emissions constraints on SOx:

\[ \sum_{n,m,j} \gamma_{i,j} \sum_{k=1}^{T} R_{i,k} - P_{i,k} \leq (E_{\text{max}}) \]

for all t

7. Non-negativity of all variables.

8. Other constraints may be imposed as needed, for instance:

- Upper limits on the reaoli efficiencies of poOation
control technologies.

- Upper limits on the awatts of plant capacities that
may be installed in a nffity or in the region.

- Upper limits on the awatts of plant capacities that
may be installed in a particular nffity.

- Constraints on SOx, at the idforaml atifity te-eL

- Constraints on the availabilities.

- Constraints on the availability of regional lereL

In order to minimize the annual at-period efforts (i.e., oaderstated
capital expenditure), it is assumed that, after the final period, the
system will operate indefinitely at those levels. To do this, the
cost coefficient for the operations variables (\# aad w) in the final
period are multiplied by 1/(1-\alpha).

3. A NEW PROCEDURE TO SOLVE THE MUP

3.1. Overview

Even with the various aggregations and averaging, for most
realistic appbention, the MUP model can be quite large. Theseiof
the problem (the number of variables and aamb of constraints) b
proportional to NX, where N is the number of wiffities in the
region, and T is the number of periods in the time horizon. For a
representative set of values of N and T (N > 10, and T > 15), the
problem becomes very large, and exisiting LP codes would have
trouble solving it ia any reasonable amovat of time. (The aamb
of constraints would exceed \(1,000\), and the aamb of variables
would exceed \(10,000\).) Therefore, a different soimtion procedure b
developed for the MUP problem.

The MUP problem decomposes, in a natural way, into several
single-period problems with the capital variables (generation
capacity and CT capacity) being the control variables. That b,
with fixed capital variable values, the problem can be divided into
everal smaller single-period electric power dispatch type problems,
ia which the plant operating leveb and inter-nffity flow are the
A few words about the decomposition are appropriate here. There are several standard ways to decompose an LP problem [1-5]. Unfortunately, the general decomposition methods offer little in the way of improved running time or diminished storage requirements over the various sparse-matrix implementation schemes of the Simplex algorithm. Instead of wing one of these, knowledge of the problem and a "means-ends" approach has been used to obtain a new decomposition method.

Using the bounds on the capital variables as controls, the decomposition, for each period,

1. allocates the total generation plant i-paasinas for the region to the individual utilities,

2. allocates the energy generation for the region to the individual utilities (i.e. determines interutility energy transfers),

3. and subdivides the region's emission caps among the individual utilities.

In making these allocations and subdivisions, the algorithm takes the interutility transmission losses and capacity into account.

Theoretically, H may be necessary to reinitialize over the periods until the solutions converge. However, in general no more than one or two iterations ought to be required for a satisfactory solution. Details of the decomposition method follow.

3.2. Assumptions

Following assumptions about the MUP problem have been made when developing a heuristic decomposition method:

1. Electric power demand b exported to increase over time, hence the total ymilion capacity requirements are expected to increase with time.

2. The time horizon of study is generally each thai, capacity brought online during the period of study will be operable at least until the end of the horizon.

3. The allowable emission limits are expected to decrease (or at least not increase) over time, hence CT capacity requirement are expected to increase with time.

4. The final period of study is a steady utility model, hence it b likely that the profile of capital additions for the solution of last the last period problem would be similar (and in many instances identical) to that for last period portion of the exact solution to MUP.

These assumptions together with other features of the MUP problem suggest the use of a means-end algorithm as the control variables. Thb algorithm essentially tries to find the optimal capital configuration for the final period (which is a steady-state problem), and works back toward the beginning periods.

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### 3.4. Single Period Problem Formulation

A formulation of the single-period problem follows:

For each period t,

\[
\text{Minimize} \sum_i \left( \sum_j \left( \sum_k r_{ik} x_{ij} + \sum_m l_{imj} x_{imj} x_{ikm} x_{jlm} x_{imj} \right) + \sum_j \left( \sum_m u_{ijm} x_{ijm} + \sum_k u_{jk} w_{ijk} \right) \right)
\]
subject to:

1. Demand constraints (generation should be at least equal to demand):

\[ \sum_{i,j} t_{ij} + \sum_{m} \omega_{m} - \sum_{n} o_{mn} \geq L_{m} \]

for all \( m \), \( n \).

2. Generation constraints (generated power should not exceed power capacity):

\[ AV_{m} \sum_{i} b_{ij} \geq AV_{m} \left( \sum_{i} P_{m} - P_{m} \right) \]

for all \( i, m, a \).

3. Capacity factor constraints (generated energy should not exceed maximum capacity):

\[ CF_{m} \sum_{i} b_{ij} \geq CF_{m} \left( \sum_{i} R_{m} - P_{m} \right) \]

for all \( i, m, a \).

4. CT (Control Technology) constraints (CT cannot exceed capacity):

\[ b_{ij} = \sum_{j} f_{ij} w_{ij} \leq 2 \sum_{t} f_{ikm} X_{ikm} \]

for all \( i, j, a \).

5. CT constraints (CT cannot remove more SO\(_2\) than is produced):

\[ \sum_{m} t_{ikm} + \sum_{j} w_{ij} \leq 0 \]

for all \( j, i, m, \).

6. Regional emissions constraints on SO\(_2\):

\[ \sum_{m} t_{ikm} + \sum_{j} w_{ij} \leq x_{ikm} \]

7. Non-negativity constraints on all variables, and

\[ P_{i,t,n} \leq P_{i,t+1,n} \]

for all \( i, n, a \) and for \( t, j, k, T \).

8. Other constraints may be imposed as needed, for instance:

   - Upper Emits on the removal efficiencies of pollution control technologies.
   - Upper limits on the amotaats of plant capacities that may be installed in the utility or the region.
   - Upper limits on the emissions of fads that may be ased by a particular utility.
   - Upper limits on inter-utility traasamission line capacity and availability.
   - Constraints on SO\(_2\), at utility level.
   - Constraints on several upper emissions such as TSP and NO\(_x\), at utility and/or repoaal level.

The special notation used here is different from that in the formulation in Section 2 is:

\[ b_{ij} = \sum_{i} p_{ij} \text{ for all } i \]

\[ z_{ij} = \sum_{i} z_{ij} \text{ for all } i \]

\[ c_{ij} = C_{ij}^{T} - C_{ij}^{T+1} / d^{T} \text{ for } t \neq T \]

\[ v_{ij} = V_{ij} - V_{ij+1} / d^{T} \text{ for } t \neq T \]

The solution procedure is implemented using the XMP linear programming package [6].

4. AN EXAMPLE

In this section, we present some of the results obtained from a study of seven utilities. Such results are at least as satisfactory to the input data as they are to the methodology. Our objectives here are to illustrate the sort of output the MUP methodology can generate. We have neither the space to present all the input data nor to comment on its accuracy. Therefore, we will not identify the utilities involved.

Information on the existing and announced generating rates for the utilities were obtained from the Unit Inventory File [7] that has been compiled for all the rates in the U.S. under another part of the project that supported this work. Much of the information on costs and characteristics of fads and control technologies was also obtained from databases and models developed for this project. The remainder of the input information, particularly on emissions ceilings and demand growths and demand shapes is conjectured.

The basic problem consists of seven utilities interconnected by lossy lines over a time horizon of 20 years that are divided into 10 periods (5 1-year periods, 2 2-year periods, 2 3-year periods, and one 5-year period) using a 2% per annum demand growth. The basic groupings or pools (defined by the transmission lines) are utilities A, C, D, and G comprising one pool and B, E, and F comprising the other, with C also randomizing to the second pool. The demand load curves used were nimitaH 3-segment load duration curves. The energy demands used for the seven utilities during the first period were approximately 12, 8, 12, 3, 24, 20, and 20 1000 GWHrs/Year. Since one of the reasons for power transfers
is differing peak times, and that using load duration curves instead of a skyline curve implies simultaneous peaking, the solution can be expected to be biased toward peaking units. (I.e. the peak shaving that power transfers can accomplish are not reflected in this example.)

Results of two runs are summarised below. The first is with an allowable emission level that is binding only during the final period; the second uses a 30% lower level that becomes binding during the final three periods. The differences in answers occur only during the final three periods (11 years) of the study. The only generation capacity added during the first 7 periods were those that were already scheduled (i.e. the model did not predict the need for other additions).

The net power transfers for four of the first seven periods are given in Table 4-1. Nuclear facilities were scheduled to come on line between 1985 and 1987 for utilities A and F, and this accounts for the change in the transfer patterns during those periods. Utilities B and C were scheduled to have coal units come on line for the 1993 period, and this accounts for most of the pattern change there.

Table 4-1: Inter-Utility Power Transfers—First Seven Periods

<table>
<thead>
<tr>
<th>Utility</th>
<th>1985</th>
<th>1987</th>
<th>1989</th>
<th>1993</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>350</td>
<td>4000</td>
<td>3000</td>
<td>2827</td>
</tr>
<tr>
<td>B</td>
<td>-2624</td>
<td>-5010</td>
<td>-3921</td>
<td>-719</td>
</tr>
<tr>
<td>C</td>
<td>-6149</td>
<td>-5935</td>
<td>-6448</td>
<td>-4006</td>
</tr>
<tr>
<td>D</td>
<td>552</td>
<td>159</td>
<td>292</td>
<td>84</td>
</tr>
<tr>
<td>E</td>
<td>4281</td>
<td>3000</td>
<td>2745</td>
<td>546</td>
</tr>
<tr>
<td>F</td>
<td>-1258</td>
<td>2630</td>
<td>1546</td>
<td>-12</td>
</tr>
<tr>
<td>G</td>
<td>4057</td>
<td>1410</td>
<td>2358</td>
<td>1011</td>
</tr>
</tbody>
</table>

The differences in flows for the two examples can be explained primarily in terms of existing non-polluting generating units that were basically uneconomical to dispatch for the loose emission constraint case, but became useful when the emission standard became tighter, raising the marginal cost of power. This occurred for utility E, and to a lesser extent, utilities B, C, and G, for periods 8 and 9 (years 1990 and 2004). In the final period, these units were utilised for both runs. It is this that accounts for utility A's difference in exported power in 1990 (utility E replaced A for exports to some extent).

5. CONCLUSIONS

A tractable model for multi-utility planning has been developed using deterministic data. It is also possible to include some uncertainties that are common to electrical power generation problems. The sorts of uncertainties that are important can be included through another heuristic and chance constrained programming.

ACKNOWLEDGEMENT

Although the information described in this paper has been funded partially by the U.S. Environmental Agency (under Assistance Agreement CR-805514 to the University of Illinois), it has not been subjected to the Agency's required peer and administrative review and therefore does not necessarily reflect the views of the Agency and no official endorsement should be inferred.

Table 4-3: Natural Gas/Coal Accumulative Additions MW

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0/0</td>
<td>314/0</td>
<td>474/0</td>
<td>119/0</td>
</tr>
<tr>
<td>B</td>
<td>0/0</td>
<td>119/0</td>
<td>119/446</td>
<td>119/446</td>
</tr>
<tr>
<td>C</td>
<td>0/0</td>
<td>670/0</td>
<td>570/935</td>
<td>570/935</td>
</tr>
<tr>
<td>D</td>
<td>0/0</td>
<td>21/0</td>
<td>156/0</td>
<td>156/0</td>
</tr>
<tr>
<td>E</td>
<td>0/0</td>
<td>0/0</td>
<td>0/1609</td>
<td>0/1609</td>
</tr>
<tr>
<td>F</td>
<td>0/0</td>
<td>0/0</td>
<td>0/1333</td>
<td>0/1333</td>
</tr>
<tr>
<td>G</td>
<td>0/0</td>
<td>517/0</td>
<td>517/0</td>
<td>517/0</td>
</tr>
</tbody>
</table>

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Table 4-2: Inter-Utility Power Transfers—Final Three Periods

<table>
<thead>
<tr>
<th>Utility</th>
<th>1990</th>
<th>1991</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>327/0</td>
<td>474/0</td>
<td>119/0</td>
</tr>
<tr>
<td>B</td>
<td>0/0</td>
<td>119/0</td>
<td>119/446</td>
</tr>
<tr>
<td>C</td>
<td>687/0</td>
<td>687/606</td>
<td>687/606</td>
</tr>
<tr>
<td>D</td>
<td>21/0</td>
<td>156/0</td>
<td>156/0</td>
</tr>
<tr>
<td>E</td>
<td>0/0</td>
<td>0/0</td>
<td>0/1609</td>
</tr>
<tr>
<td>F</td>
<td>0/0</td>
<td>0/0</td>
<td>0/1333</td>
</tr>
<tr>
<td>G</td>
<td>517/0</td>
<td>517/0</td>
<td>517/0</td>
</tr>
</tbody>
</table>

Tables 4-2 and 4-3 summarize the inter-utility transfers and generation additions, respectively, for the last three periods of the two runs. Even though four different generation technologies were permitted, (natural gas, oil, nuclear, and coal), only natural gas (for a peaking unit) and coal (for a base unit) were selected by MUP. The differences in the generation additions for the two runs are slight. Utility A brings on 17 more MW of peak capacity earlier for the tighter emission standard case, and utility C builds slightly less coal and more peak for the tighter emission case.
REFERENCES


