Simulation Model of Transmission Constrained Hydrothermal Power System

Skuli Johannsson, Annad veldi ehf, Reykjavik, Iceland, skuli@veldi.is
Elias B Eliasson, The National Power Company, Iceland, elias@lv.is

01-August-2003
Revised 09-Dec-2003

Introduction

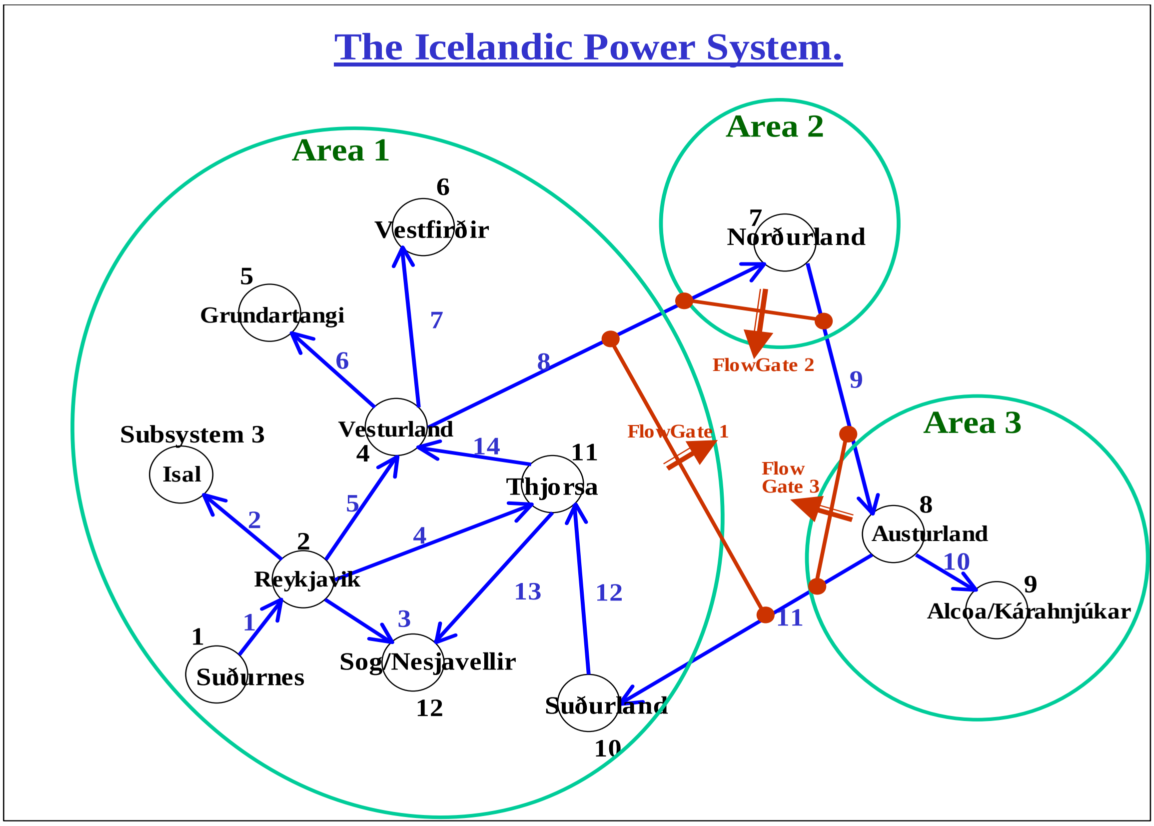
Usually simulation models for operational studies of Hydrothermal Power Systems have only in a limited way accounted for the transmission system because of the complexity of modelling and lengthy calculations involved. In [1] we introduced a new computer model specially designed for studying the Icelandic electrical power system. Using this new model it is possible to study transmission expansion as an alternative to building new power plants, demonstrating that there exists a level of competition between these two types of investments.

The interaction between the production and transmission system is particularly important in hydro systems as hydro plants have to be located where the natural resource is to be found and it tends to be far away from the market. On the other hand thermal plants can be built just about anywhere.

The methodology has been developed further making it possible to perform comprehensive analyses of a new transmission tariff structure as called for by the recently deregulated power system in Iceland. The model is developed using a representation of the power system as in figure 1, but for actual studies a more detailed one is required.

The power system consists of 3 areas, 12 subsystems and 14 transmission lines. Each subsystem has its own market and generation capacity of hydro, geothermal and/or thermal power plants. For model purposes the transmission lines are direction oriented. Number of hydro and geothermal plants in the model is 32 and number of reservoirs is 8.

Figure 1



The system is defined by 12 Subsystems, 14 directed Transmission Lines, 3 Areas and 3 directed Flow Gates.

Iteration

The method in [1] is based on the following procedure:

1. Initiate. The load in every subsystem is assumed to be the local market with no transmission between the subsystems.
2. Strategic part. Calculation of water values in each subsystem.
3. Tactical part. Simulation of the whole Power system using all available daily or weekly river flow series (1950-2000). The operation is optimised for each time stage using thermal generation to estimate immediate cost and the water values to estimate future cost.
4. Reallocate Power load in subsystems according to transmission in the last iteration.

5. If stop criterion is not obtained then start again on step 2.
6. Else write out the results.

By experience convergence is obtained in 5 iterations

Water values

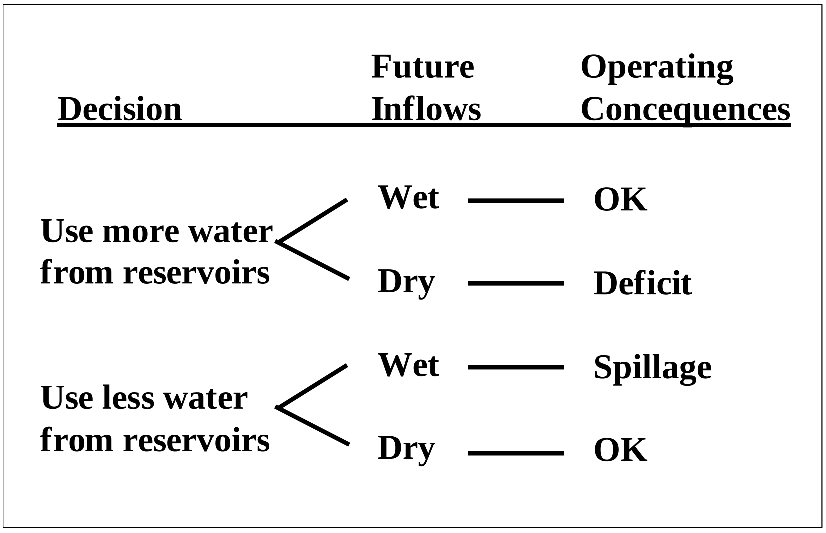
In Iceland simulation studies are based on records of 51 years of historical river flows. In view of recent theories on climate changes it is more controversial than ever before that similar stochastic behavior of the water flows should be expected throughout coming years. Never the less, using historical data to estimate future consequences of operational decisions and for risk management is still the most widely accepted method and as the actual series are used directly it is simple to replace them with stochastic series unique for any climate scenario.

Using reservoirs it is possible to store excess water in the summer when demand is at minimum to be used in the wintertime when demand is high and water is low.

If water from reservoirs is used too early it may be necessary to use expensive thermal power or suffer power shortages with huge costs in late winter when reservoirs go empty. On the other hand if the water is used too conservatively i.e. by curtailment of secondary power at a too early stage then there will still be plenty of water left in reservoirs when river flow increases in the spring resulting in worthless spills of water in late summer.

Water value is way to evaluate operational cost for the power system in the future that can be avoided by storing water in reservoirs for later use instead of using it immediately. The decision process can be explained in a decision tree:

Figure 3 Decision tree



The calculation of water values is described in [1].

Simulation

Figure 3 shows a simplified model of a hydro power plant connected to the transmission network.

Inflows are $\Sigma[u_{m,t} + s_{m,t}]$ from next upstream plants and $r_{i,t}$ as lateral flow. Outflows are turbined water $u_{i,t}$ and spilled water $s_{i,t}$. Reservoir volume is $v_{i,t}$ and power production is $\rho_i(v_{i,t}) \cdot u_{i,t}$.

Geothermal plants are presently modelled as run of the river hydro plants with neither reservoirs nor upstream plants.

Given the value water in reservoirs and cost of thermal production and curtailment of power the tactical problem can be defined:

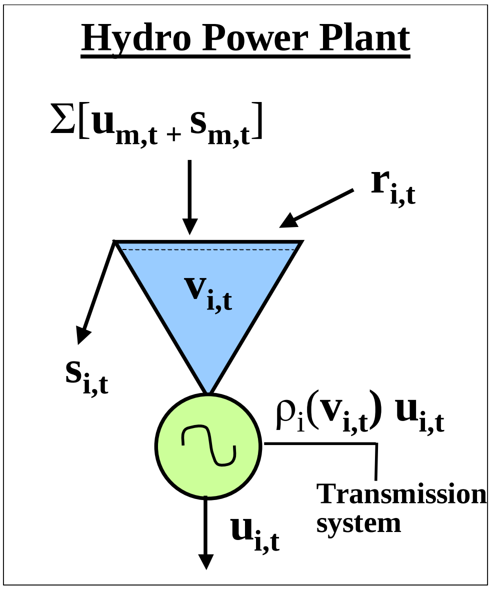


Figure 3

Objective function for every stage t of the planning period T is:

$$\min\left(\sum_j c_j \cdot g_{j,t} + \beta \cdot \sum_k \rho_k(v_t) \cdot \alpha_{s,t+1} \cdot v_{k,t+1} + \psi_a \cdot S_a\right) \tag{1}$$

Subject to:

Load supply for every subsystem; continuity equation for electricity:

$$\sum_{i \in s} \rho_i(v_t) \cdot u_{i,t} + \sum_{j \in s} g_{j,t} - \sum_{n \in s}(1+\tau_n) \cdot L_n^+ + \sum_{n \in s} L_n^- = w_{s,t} \tag{2}$$

Water balance for every hydro power station; continuity equation for water:

$$v_{i,t+1} = v_{i,t} - u_{i,t} - s_{i,t} + r_{i,t} + \sum_{m \in Ui}\left[u_{m,t} + s_{m,t}\right] \tag{3}$$

Limits on reservoir storage: $v_i^{\min} \le v_{i,t} \le v_i^{\max}$ (4)

Limits on turbined water: $u_i^{\min} \le u_{i,t} \le u_i^{\max}$ (5)

Limits on spilled water: $s_i^{\min} \le s_{i,t} \le s_i^{\max}$ (6)

Limits on thermal generation: $g_{j,t} \le g_j^{\max}$ (7)

Transmission line capacity: $L_n^+ \le L_n^{\max} \quad L_n^- \le L_n^{\max}$ (8)

Limits on transmission capacity in Flow Gates (*FG*):

$$\begin{gathered}\sum_{n \in FG} f_n^+ \cdot L_n^+ + \sum_{n \in FG} f_n^- \cdot L_n^- \le L_a^* \\ \sum_{n \in FG}(1-f_n^+) \cdot L_n^+ + \sum_{n \in FG}(1-f_n^-) \cdot L_n^- \le L_a^*\end{gathered} \tag{9}$$

Spinning reserve requirement in hydro and geothermal plants for each area:

$$\sum_{i \in a} \rho_i(v_t) \cdot u_{i,t} - S_a \le (1-\sigma_a) \cdot \sum_{i \in a} \rho_i(v_t) \cdot u_i^{\max} \tag{10}$$

Where:

t:	time index
T:	planning period
a:	area index
s:	subsystem index
k:	reservoir index
j:	thermal plant index
i:	hydro plant index
m:	index for upstream hydro plants
n:	transmission line index
$v_{i,t}$	Stored volume at plant i at the beginning of stage t
$v_{i,t+1}$	Stored volume at plant i at the end of stage t
$r_{i,t}$	Lateral river flow arriving at power station i in stage t
$u_{i,t}$	Turbined outflow at power station i in stage t
$u_{i,t}$	Spilled outflow at power station i in stage t
U_i	Set of hydro plants immediately upstream of plant i
$g_{i,t}$	Generation of thermal plant j in stage t
c_j	Generation cost of thermal plant j
$\sum_j c_j \cdot g_{j,t}$	The immediate thermal operating cost in stage t

$\sum_k \rho_k(v_{t+1}) \cdot \alpha_{k,t+1} \cdot v_{k,t+1}$ The future cost represented by:

$\rho_k(v_{t+1})$	The production coefficient of reservoir k	[kWh/kl]
$\alpha_{s,t+1}$	The water value for subsystem k	[kr/kWh]
$v_{k,t+1}$	Reservoir volume at the end of stage t	[kl]

β:	Discount factor
L_n^+	Transmission in positive direction between subsystems
L_n^-	Transmission in negative direction between subsystems
τ_n	Transmission losses
L_{FG}*	Limit on transmission in Flow Gates.
f_n^+	=1 if direction of transmission line is the same as direction of Flow Gate, else=0.
f_n^-	=1 if direction of transmission line is the opposite to direction of Flow Gate, else=0.
ψ_a	Penalty factor for spinning reserve requirement in area
S_a	Lack of spinning reserve
σ_a	Spinning reserve requirements, i.e. σ_{week}=0,10 and σ_{day}=0,075
$w_{s,t}$	Energy market in a subsystem
$w_{a,t}$	Energy market in an area

Results

Figure 4 shows typical results of a 1-year simulation run with 1 week time units. Computer time on a PC-workstation (2.4 GHz, 1GB Memory) was 80 sec. That involves solving the LP-problem (1)-(10) 51*52*5=13260 times with Solver DLL from Frontline Systems (51 water years, 52 weeks/year and 5 iterations).

The program has been used successfully for planning periods of 20-25 years with weekly time units

Using the model for simulation of daily operation of the power system for up to 8-year time has also given good results. Practical use of daily simulations will most probably be limited to 1-3 years.

Figure 4

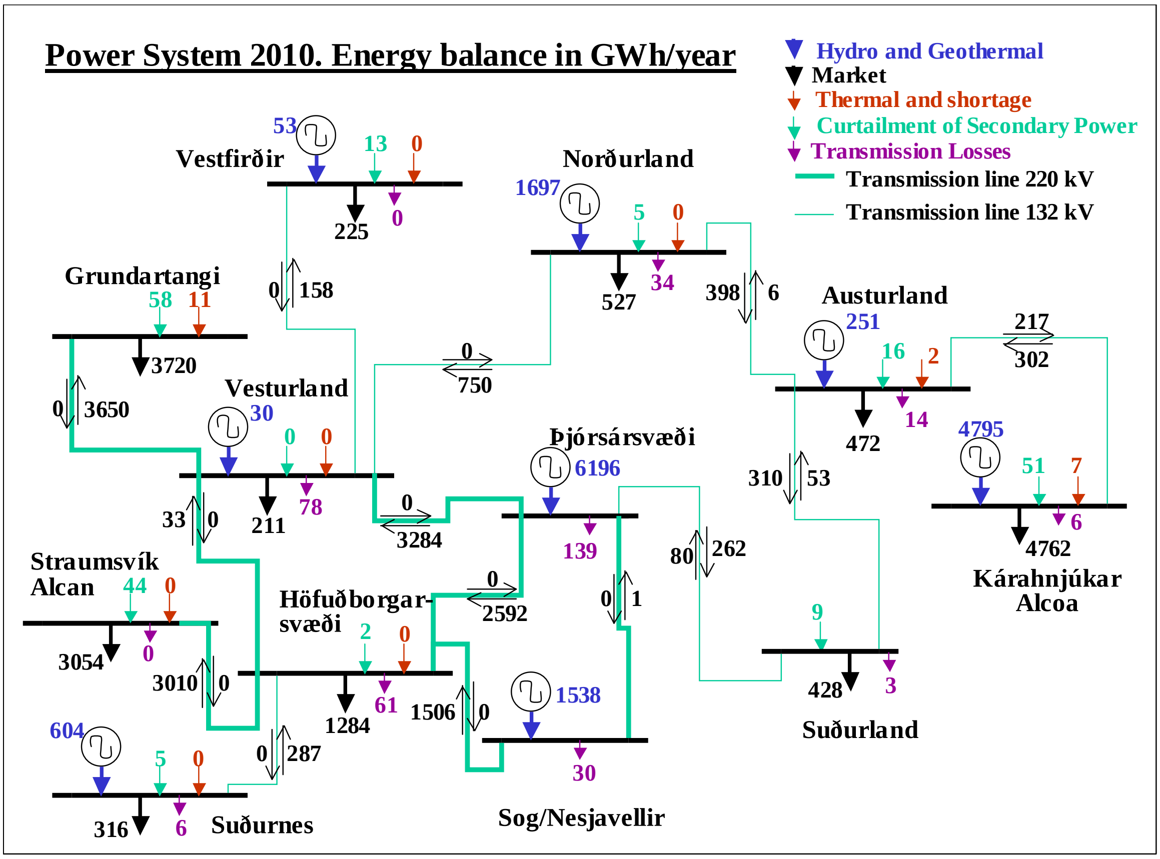
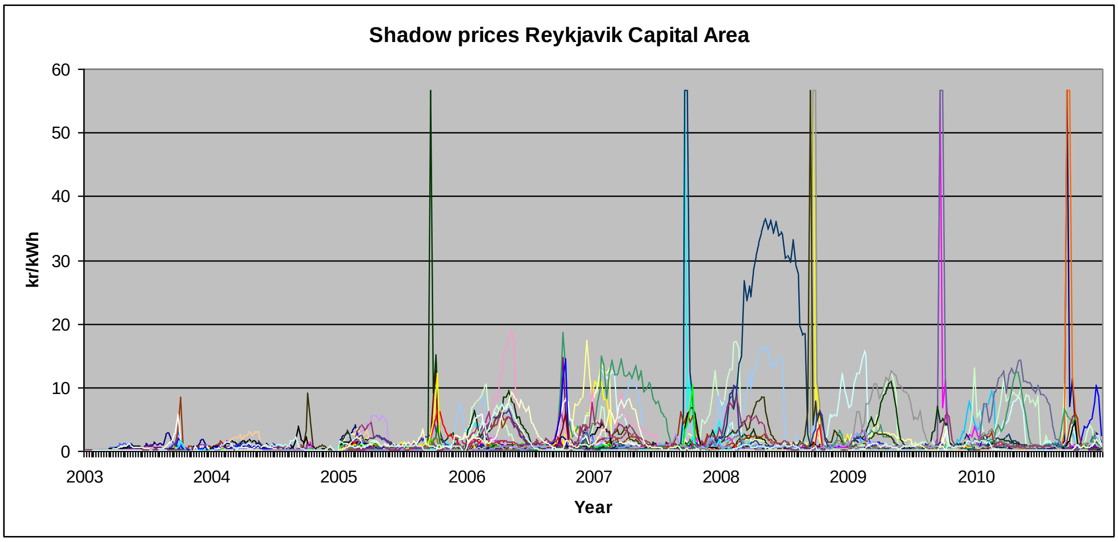


Figure 5 shows simulated shadow price of the energy market in Reykjavik Capital Area for the period 2003-2010, one curve for every water year of 51 available years. The scenario is based on one probable market develop-ment and corresponding power projects investments.

Figure 5



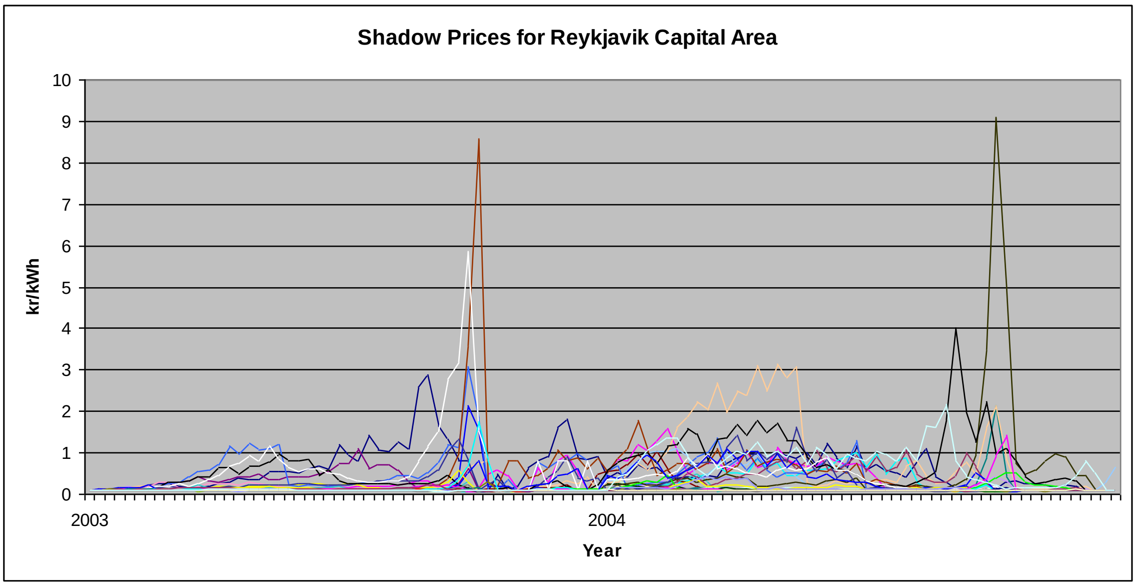
In year 2006 and later shadow prices can in dry water years reach highest power shortage cost 58.3 kr/kWh.

The figure reveals operational characteristics of hydro dominant electrical power systems. Low river flow occurs infrequently so variable operational costs are low in general. However in dry water years, especially just before entry of additional power generation capacity, operational cost can increase drastically due to high penalties for energy shortage. Market theories dictate, that in such cases actual sales prices should be raised in order to decrease demand and thus avoid more severe shortages. In the most severe cases however, both high prices and shortages can cause massive negative economical and social impacts on society.

Hydro dominated power systems are to a much higher degree than other power systems governed by the law: “Something rarely goes wrong but when it does disaster strikes”.

Figure 6 shows in more detail the years 2003-2004. The cost of curtailment of secondary power, the cheapest form of reserve, is 0.94 kr/kWh.

Figure 6



Including the transmission system in the model facilitates a detailed estimate of local shadow prices. Shadow prices are the key to estimate the system short-run marginal cost SRMC in hydro power system which in turn affects directly the pricing mechanism on the free market. Detailed estimates of shadow prices at hydro plants are also important in operation planning thus contributing to better utilization of the system and lower overall power prices. This methodology will be increasingly important in the coming years and leading the way into the new order of deregulation of the electrical power industry in Iceland.

References

[1]: Skuli Johannsson Annad veldi ehf Reykjavik Iceland skuli@veldi.is, Elias B Eliasson Landsvirkjun Reykjavik Iceland elias@lv.is: “Simulation Model of the Hydro-Thermal Power System in Iceland” 14. June 2002. Published at www.veldi.is